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Reduction of Stack Emissions During Startup, Shutdown, and Malfunction

Malmstrom Air Force Base, MT

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Foreword

This study was conducted for Malmstrom Air Force Base, MT, under Military Interdepartmental Purchase Requests (MIPRs) No. N341CES0123026, "Reduction of Stack Emissions During Startup and Shutdown at Malmstrom Air Force Base, MT," and N341CES0123027/PO, "Evaluate Air Emission Situation at Base Heat Plant." The technical monitors were Mr. William Reid and Mr. David Heckler, CES/CEOE.

The work was performed by the Energy Branch (CF-E) of the Facilities Division (CF), Construction Engineering Research Laboratory (CERL). The CERL principal investigator was John L. Vavrin. Dr. Tom Hartranft is Chief, CEERD-CF-E, and Mr. L. Michael Golish is Chief, CEERD-CF. The associated Technical Director was Gary W. Schanche, CEERD-CV-T. The technical editor was William J. Wolfe, Information Technology Laboratory. The Director of CERL is Dr. Alan W. Moore.

CERL is an element of the U.S. Army Engineer Research and Development Center (ERDC), U.S. Army Corps of Engineers. The Commander and Executive Director of ERDC is COL John Morris III, EN and the Director of ERDC is Dr. James R. Houston.

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1 Introduction

Background

The Coal Fired Heat Plant (CFHP) at Malmstrom Air Force Base (MAFB), MT is designed to fire both natural gas and sub-bituminous coal. To achieve this, the plant uses three generators: one designed to burn coal, one designed to burn either coal or natural gas (a “dual-fueled” unit), and one designed to burn natural gas. The three generators provide high temperature hot water (HTHW) to the entire base. The dual-fuel generator (operated with coal), and the coal-fired spreader stoker generator each have an input capacity of 106 million Btu per hour (MMBtu/hr) and an output capacity of 85 MMBtu/hr. The dual-fuel generator (operated with natural gas) and the natural-gas-fired generator can each yield a maximum output capacity of approximately 30 MMBtu/hr (for a combined total of 60 MMBtu/hr).

The use of coal at MAFB offers some operational advantages. One coal-burning generator can provide ample heat for the entire base. (In this circumstance, a second generator would serve as a standby unit.) Although MAFB uses natural gas in the spring and fall to heat the entire installation, two generators fired on gas (and operating at capacity) may not provide adequate heat for the entire base during extremely cold periods—the base must use coal to meet its winter heating needs.

Under normal operating conditions, the coal-fired generators meet the Montana Department of Environmental Quality (MDEQ) emission standards. However, under certain nonstandard conditions, the plant may exceed emission limits. During startup procedures, for example, the spray dryer absorber (SDA) and baghouse must be bypassed until the flue gas temperature reaches a level that will not cause damage to the baghouse or cause plugging of the SDA unit with slaked lime. Emission limits may often be exceeded for up to one-half hour or more during these startup periods. Emission limits may also be violated when the scrubber is bypassed while the plant is operating to remove material buildup in the SDA unit. All such periods when the permit emission limits may be exceeded are considered a violation of the MAFB Title V permit.

While the MAFB Title V Permit, Section III B.9 does make allowance for the startup operating procedures, it does not relax emission limits:

> During the startup periods of boiler No. 1 and No. 3, when combusting coal, the scrubber and baghouse may be bypassed until the exhaust gas temperature reaches 350 degrees Fahrenheit, provided no emission limits are violated (ARM [Administrative Rules of Montana] 17.8.715).

MAFB tasked the U.S. Army Engineer Research and Development Center, Construction Engineering Research Laboratory (ERDC/CERL) to conduct a study to determine emission limits during startup, shutdown, malfunction, and scrubber bypass, to make appropriate recommendations to help MAFB maintain the heat plant in compliance with permit requirements at all times when fired on coal, or to recommend alternative fuels and equipment to maintain compliance.

Objectives

The objectives of part of the study were:

1. To ensure that the MAFB Heat Plant maintains emission levels, at all times, below the allowable limits established by their operating permit, State, and Federal environmental agencies.
2. If necessary, to develop a technical basis for revising the operating permit to allow reasonable emissions during system startup and shutdown.

A further objective, to be expanded in a later report, was to analyze MAFB's energy needs using HeatMap software to determine heating system alternatives.

Approach

1. *Determine emission limits qualitatively*. The team conducted a study to provide estimated amounts of pollutants emitted during startup/shutdown (SU/SD) and scrubber bypass. The study included current methods of operation and variations of current methods that may reduce emissions. Researchers estimated emissions using current fuel composition, under best case conditions using available "clean" fuels, and worst-case conditions, using AP-42 guidelines.
2. *Compare costs for all methods using current and expected fuel prices.* This comparison was based on Chapter 7 of CERL Technical Report 99/101, *NOx Evaluation of Coal-Fired Heat Plant at Malmstrom AFB, MT*.

3. *Evaluate plant modifications*. The team surveyed methods used by other similar coal fired facilities to comply with U.S. Environmental Protection Agency (USEPA) requirements. These methods were evaluated and improved where necessary to ensure that no emission limits in the MAFB permits would be violated during SU/SD, scrubber cleaning, or normal plant operation. For each acceptable method, the team determined required equipment, plant modifications, and procedural modifications. Cost analyses included equipment, materials, and labor for installation, startup, and operation. The team made recommendations based on performance/life cycle cost.

4. *Determine SIP language revision for startup and shutdown*. This task determined data and language required to request a change to the Montana SIP to allow for noncompliant periods. If no equipment was available to allow the heat plant to meet all emission requirements, the final report was to include data to support a request directed to the MDEQ to alter the SIP to allow for this noncompliant period. Any permit change will be in accordance with USEPA requirements. Revisions meet the following requirements:

   a. The revision must be limited to specific, narrowly defined source categories using specific control strategies (e.g., cogeneration facilities burning natural gas and using selective catalytic reduction).

   b. Use of the control strategy for this source category must be technically infeasible during startup or shutdown periods.

   c. The frequency and duration of operation in startup or shutdown mode must be minimized to the maximum extent practicable.

   d. Any justification of the SIP revision must include an analysis of the potential worst_case emissions that could occur during startup and shutdown.

   e. All possible steps must be taken to minimize the impact of emissions during startup and shutdown on ambient air quality.

   f. At all times, the facility must be operated in a manner consistent with good practice for minimizing emissions, and the source must have used best efforts regarding planning, design, and operating procedures to meet the otherwise applicable emission limitation.

   g. The owner or operator's actions during startup and shutdown periods must be documented by properly signed, contemporaneous operating logs, or other relevant evidence.

5. *Evaluate alternative methods to coal for providing heat to Malmstrom AFB*. The team also addressed alternative methods of providing heat to the base as equip-

ment modifications may not be available to control emissions at start up and changing the SIP may not be possible:

a. The team evaluated cost effective methods of providing heat to the base facilities with backup provisions should the primary source of fuel supply be temporarily curtailed.

b. The team investigated the cost of adding additional boilers needed for heat supply and backup to achieve the desired heat output if natural gas is the primary fuel source.

c. Decentralization of the heat supply was one method evaluated with installation of separate gas fired boilers located at each building on the base.

d. Other alternative considered methods included centrally fired facilities, fired on natural gas, propane, diesel, JP-8, etc., and any alternative method that would be cost effective.

e. Plant modifications required to accommodate the fuel types will be discussed. Additional boilers may be required to provide primary or standby units.

f. Detailed estimates of the decentralization alternatives and all other feasible alternates included construction costs and operating and maintenance labor costs.

6. Recommendations were made based on the best combination of fuels and equipment in lieu of coal, on cost, fuel availability, fuel source, reliability, backup fuel storage limitations, and environmental concerns.

Mode of Technology Transfer

The results of this study will be transmitted to MAFB for implementation, and will be made available through the World Wide Web (WWW) at URL:
www.cecer.army.mil

CERL will use the results of this work to provide lessons learned to other stoker CFHPs to support both Federal and private sector goals to improve air quality.

Units of Weight and Measure

U.S. standard units of measure are used throughout this report. A table of conversion factors for Standard International (SI) units is provided below.

SI conversion factors		
1 in.	=	2.54 cm
1 ft	=	0.305 m
1 gal	=	3.78 L
1 kip	=	453 kg
1 psi	=	6.89 kPa
°F	=	(°C x 1.8) + 32

2 Emission Results

Quantitative Emission Results

Background

The Clean Air Act provides the principal framework for National, State, and local efforts to protect air quality. Under the Clean Air Act, The Office of Air Quality Planning and Standards (OAQPS) is responsible for setting standards, also known as National Ambient Air Quality Standards (NAAQS), for pollutants considered harmful to people and the environment. OAQPS is also responsible for ensuring that these air quality standards are met, or attained (in cooperation with State, Tribal, and local governments) through National standards and strategies to control pollutant emissions from automobiles, factories, and other sources. To this end, the MAFB CFHP has been permitted to operate within certain emission limitations.

Allowable Emissions

Appendix A outlines the various emission standards required by the USEPA, the MDEQ and the limits imposed in MAFB's CFHP permit.

2001 Stack Emissions Test Results

Appendix B includes a summary of the results of MAFB's most recent stack emission tests, conducted by Energy & Environmental Measurement Corp. in February 2001. Testing was done using USEPA approved methods. Appendix B gives test results, by pollutant, for each boiler. Per testing requirements, each generator was operating at 90 percent or greater of its maximum continuous rating load. The staff at MAFB has quantitatively demonstrated that they operate their CFHP at high operating loads well under the maximum emission permit limits.

Qualitative Emission Results

Background

As part of the initial investigation, CERL completed an exhaustive literature search for quantitative results of emissions testing at other coal-fired heating plants during startup and shutdown (Appendix C). This search was undertaken to discern whether other plant operators had made constructive operational and/or maintenance changes to reduce emissions to meet permit limits during startup and shutdown, and if those "Lessons Learned" might be applicable at Malmstrom AFB. The search found no published literature on the subject. One possible reason for lack of published test results is the requirement for isokinetics, matching the rate of flow up the stack with the rate at which the sample is pulled. The USEPA 40 CFR 60 Appendix A, Reference Method 1-5 requires isokinetics for stack testing. Yet, the airflow condition is neither constant nor at minimum necessary velocity during startup and shutdown. Therefore, proper testing at that point would be extremely difficult and such changing conditions would be a matter not easily or readily repeated. Consequently, any results would not be consistent and the data considered suspect. Therefore, a qualitative study of emission rates was required to determine if Malmstrom AFB could meet its permit limits.

Equipment and Emissions During Normal Coal Operations

This section considers:
- emissions of flue gas from one boiler
- coal-fired Boilers No. 1 or No. 3
- existing normal coal operation over capacity range.

Appendix D to this report includes diagrams of flue gas flow and proposed modifications discussed throughout this report. Figure D1 shows a general diagram of the components, and of air and flue gas flow for a typical coal-fired boiler. The normal coal combustion operation for Boiler No. 1 or No. 3 is in compliance with the MDEQ limits and regulations over the complete capacity range of operation. Table 1 summarizes the data condensed from Table E1 (included in Appendix E to this report). (Figure D2 shows a diagram of flue gas flow during this operation.) Table E1 also includes a summary of the equipment and emission limits if all air pollution control devices were completely bypassed (uncontrolled). In this scenario, all permit limits would be exceeded.

Table 1. Summary of estimated emissions over normal operating range, coal-fired.

Type of Emission	USEPA Permit Limits	Plant Operational Range of Emissions
Particulate		
lb/hr	4.0	0.47 to 1.88
Opacity, %	20%	5% to 5%
Nitrogen oxides		
lb/MMBTU heat input	0.50	0.35 to 0.31
lb/hr	53.0	12.4 to 32.9
Sulfur oxides		
lb/MMBtu Heat Input	0.32	0.29 to 0.19
lb/hr	33.9	6.80 to 18.05

Table 2. Summary of estimated emissions over normal operating range, natural gas-fired

Type of Emission	USEPA Permit Limits	Plant Operational Range of Emissions
Particulate		
lb/hr	4.0	0.01 To 0.07
Opacity, %	20%	0% To 2%
Nitrogen oxides		
lb/MMBTU heat input	0.50	0.07 To 0.11
lb/hr	53.0	0.52 To 2.37
Sulfur oxides		
lb/MMBTU heat input	0.32	0.00067
lb/hr	33.9	0.0031 To 0.0226

Equipment and Emissions During Normal Natural Gas Operations

This section considers:

- emissions of flue gas from one boiler
- natural gas-fired Boiler No. 1 or No. 2
- existing normal natural gas operation over capacity range.

The normal natural gas combustion operation for boiler No. 1 or No. 2 is in compliance with the MDEQ limits and regulations over the complete capacity range of operation. Figure D3 shows a diagram of flue gas flow during natural gas operation. Normal natural gas operation bypasses the baghouse and SDA. Table 2 summarizes the data condensed from Table E2. Table E2 also includes a summary of the equipment and emission limits if all air pollution control devices were completely bypassed (uncontrolled). In this scenario, all permit limits were met. (The limits of particulate and sulfur oxides are normally not tested because the inaccuracy of the test is greater than the emissions.)

Equipment and Emissions During Startup and Shutdown (SU/SD)

Typical CFHP 5-hr Startup

This section considers:

- emissions of flue gas from one boiler
- normal 5-hr coal startup of existing equipment.

Note that this is not Malmstrom AFB's current operational startup procedure. However, this is a typical startup cycle for most coal-fired boilers. The startup of most coal fired stoker boilers requires a minimum of 5 hours. The ASME boiler and pressure vessel code recommends that the pressure parts of drums, headers, and tubes of a fired pressure vessel must be heated sufficiently and slowly to prevent injury to personnel or failure of the pressure parts. Schmidt Associates, Inc. (engineer consultants) was asked by Ford Motor Company to provide a technical summary of the importance of a minimum 5-hr startup. Appendix F includes a copy of this 1991 letter in its entirety.

This startup should form the standard (and basis for comparison) for all other systems. If the baghouse is put into operation at the initial operation of coal combustion, the nitrogen oxides and sulfur oxides must be addressed in relation to startup. Tables 3, 4, and 5 summarize the data condensed from Table E3. Emission limits are exceeded for particulates, opacity, NOx, and Sox during the first 3 hours. During an uncontrolled situation, all other emission limits are exceeded as well. Figure D4 shows a diagrams of flue gas flow during this operation.

Table 3. Summary of estimated emissions during the first 3 hr of a normal 5-hr startup, coal-fired.

Type of Emission	USEPA Permit Limits	Plant Operational Range of Emissions
Particulate		
lb/hr	4.0	8.0 to 21.24
Opacity, %	20%	80% to 50%
Nitrogen oxides		
lb/MMBtu heat input	0.50	0.75 to 1.00
lb/hr	53.0	8.00 to 16.43
Sulfur oxides		
lb/MMBtu heat input	0.32	0.57
lb/hr	33.9	4.56 to 12.48

Table 4. Summary of estimated emissions during the 4th and 5th hours of a normal 5-hr start-up, coal-fired.

Type of Emission	USEPA Permit Limits	Plant Operational Range of Emissions
Particulate		
lb/hr	4.0	0.53 to 0.60
Opacity, %	20%	5%
Nitrogen oxides		
lb/MMBtu heat input	0.50	0.40 to 0.50
lb/hr	53.0	12.00 to 13.25
Sulfur oxides		
lb/MMBtu heat input	0.32	0.192 to 0.38
lb/hr	33.9	5.76 to 10.07

Table 5. Summary of estimated emissions during a normal startup, coal-fired.

Type of Emission	USEPA Permit Limits	Plant Operational Hourly Average Emissions
Particulate		
lb/hr	4.0	8.95
Opacity, %	20%	40%
Nitrogen oxides		
lb/MMBtu heat input	0.50	0.62
lb/hr	53.0	12.53
Sulfur oxides		
lb/MMBtu heat input	0.32	0.41
lb/hr	33.9	8.22

Table 4 summarizes the fourth and fifth hours of the normal 5-hr startup. These 2 hr of a normal 5-hr startup are in compliance (except one-half hour of sulfur oxides). Table 5 summarizes the entire five 5-hr startup (the 5-hr average of emissions). Note that these 5 hr average emissions of a normal 5-hr startup are non-compliant. Figure D5 shows a diagrams of flue gas flow during the fourth and fifth hours of operation.

MAFB CFHP 3-hr Startup

This section considers:

- emissions of flue gas from one boiler
- coal-fired Boiler No. 1 or No. 3
- a 3-hr coal startup of existing equipment
- circulating HTHW for 5 hr before coal light off.

This is Malmstrom AFB's current operational startup procedure. The startup of MAFB's coal-fired stoker boiler is normally shortened to 3 hr. The following steps are taken to achieve the 3-hr startup time:

1. The plant will start up and operate in the fall (01 to 14 October) on natural gas combustion either on Boiler No. 1 or Unit No. 2.
2. They slowly increase the HTHW to 350 °F over a week to 10 days. The stack emissions are in compliance for all regulated limits because the plant is firing natural gas only. See Appendix E.
3. When the heating load of the system increases sufficiently, a coal-fired HTHW boiler is prepared for startup by circulating 350 to 400 °F HTHW through the unit for 5 hr or longer. The circulating 350 to 400 °F HTHW warms up the ASME code pressure parts to 75 percent of the final temperature.

During the first hour of coal combustion for the 3-hr startup, the spray dryer and baghouse are bypassed to warm up the mechanical dust collector and air heater. Tables 6, 7, and 8 summarize the data condensed from Table E4. During the first hour of operation, the CFHP exceeds its permit limits for particulates, opacity, SOx, and NOx. Figure D6 shows diagrams of flue gas flow during this operation.

During the second and third hour of coal combustion for the 3-hr startup, the flue gas flows through the spray dryer and baghouse (Table 7). The spray dryer has chemical feed or sulfur oxide reduction for only 1½ hr of the 2 hr. When the baghouse and spray dryer are engaged (the second and third hours), the CFHP meets all its permit limits. Table 8 lists the 3-hr average emissions (which are noncompliant). Figure D7 shows a diagrams of flue gas flow during the second and third hours of operation.

Shutdown

This section considers:

- emissions of flue gas from one boiler
- coal-fired Boiler No. 1 or No. 3
- shutdown of coal boiler and pollution control equipment.

Table 6. Summary of estimated emissions during MAFB'S first hour startup, coal-fired.

Type of Emission	USEPA Permit Limits	Plant Operational Range of Emissions
Particulate		
lb/hr	4.0	20.56
Opacity, %	20%	65%
Nitrogen oxides		
lb/Btu Heat Input	0.50	0.75
lb/hr	53.0	15.90
Sulfur oxides		
lb/Btu Heat Input	0.32	0.57
lb/hr	33.9	12.08

Table 7. Summary of estimated emissions during MAFB'S 2ᵈ and 3ᵈ hour startup, coal-fired.

Type of Emission	USEPA Permit Limits	Plant Operational Range of Emissions
Particulate		
lb/hr	4.0	0.53 to 0.60
Opacity, %	20%	5%
Nitrogen oxides		
lb/MMBtu Heat Input	0.50	0.50 to 0.40
lb/hr	53.0	13.25 to 12.00
Sulfur oxides		
lb/MMBtu Heat Input	0.32	0.38 to 0.192
lb/hr	33.9	10.07 to 5.76

Table 8. Summary of estimated emissions during MAFB's start-up, coal-fired.

Type of Emission	USEPA Permit Limits	Plant Operational Hourly Average Emissions
Particulate		
lb/hr	4.0	7.23
Opacity, %	20%	25%
Nitrogen oxides		
lb/MMBtu heat input	0.50	0.53
lb/hr	53.0	13.72
Sulfur oxides		
lb/MMBtu heat input	0.32	0.36
lb/hr	33.9	9.30

The CFHP uses the following sequence during the shutdown of Boiler No. 1 and Boiler No. 3 when firing coal:

1. Reduce boiler load to minimum fire for 1 hr with the spray dryer and baghouse in operation.
2. After 1 hr a minimum load, stop feeding coal by pulling the coal feeder “dogs” and stop the coal grate travel.
3. Five minutes after stopping coal feed and grate, stop forced draft fan.
4. After 10 minutes after stopping coal feed and grate, stop induced, draft fan and chemical feed to spray dryer.
5. Boiler is now allowed to cool down and no emissions are emitted.

Table 9 lists the results condensed from Table E5. The CFHP remains in compliance during shutdown. However, if the plant were in an uncontrolled situation, it would not be in compliance.

Table 9. Summary of estimated emissions during MAFB’s shutdown, coal-fired.

Type of Emission	USEPA Permit Limits	Plant Operational Range of Emissions
Particulate		
lb/hr	4.0	0.04 to 0.47
Opacity, %	20%	0.8% to 5%
Nitrogen oxides		
lb/MMBtu heat input	0.50	0.35
lb/hr	53.0	0.70 to 8.26
Sulfur oxides		
lb/MMBtu heat input	0.32	0.05 to 0.29
lb/hr	33.9	0.10 to 6.84

Table 10. Summary of estimated emission rates during a malfunction at the CFHP.

Type of Emission	USEPA Permit Limits	Plant Operational Range of Emissions
Particulate		
lb/hr	4.0	0.04 to 20.56
Opacity, %	20%	0.8% to 65%
Nitrogen oxides		
lb/MMBtu heat input	0.50	0.35 to 0.75
lb/hr	53.0	0.70 to 15.90
Sulfur oxides		
lb/MMBtu heat input	0.32	0.05 to 0.57
lb/hr	33.9	0.10 to 12.08

Malfunction of Air Pollution Control Equipment

Malfunction During Current Operations

Almost any malfunction in the CFHP's current configuration would cause the plant to exceed its permit limits. During higher heating loads, the CFHP would immediately have to start-up another coal-fired boiler using current procedures. Emission rates would be similar to those found in Table 10 (condensed form Tables E4 and E5). Table 10 summarizes the results of the 3-hr changeover with the existing air heater combustion air ductwork. In its current design, the CFHP will exceed emission limits during a malfunction. Figure D8 shows a diagram of flue gas flow during this operation.

Malfunction During Options A and B

This section considers:

- emissions of flue gas from one boiler
- coal fired Boiler No. 1 or No. 3
- coal boiler malfunction with bypass to Boiler No. 2 spray
- dryer and baghouse with revised breeching and ductwork.

Boiler No. 1 and No. 3 would each have additional flue gas breeching installed to allow the flue gas from each of the air heater outlets to flow to Boiler No. 2 spray dryer and baghouse. This breeching would be used in the event of a malfunction of the spray dryer or baghouse that serves either Boiler No. 1 or No. 3.

The baghouse serving Boiler No. 2 would become a "sacrificial" baghouse in terms of bag life. Switching the flue gas flow from Boiler No. 1 or Boiler No. 3 into the cold spray dryer and baghouse of Boiler No. 2 will cause acid condensation until the system temperature stabilizes. This will require more frequent bag replacement in baghouse of Boiler No. 2.

There are usually a couple hours of poor operating indications of the spray dryer for Boiler No. 1 or Boiler No. 3 before their malfunction. This will allow time to startup Boiler No. 2 on natural gas and warm-up spray dryer and baghouse for Boiler No. 2. (Note: The operators have never had an immediate failure of the spray dryer)

When either Boiler No. 1 or No. 3 individual baghouses are failing, the opacity (stack particulate light density) increases. The plant personnel have adequate warnings of opacity change during the cleaning cycle. When a single bag fails, the stack opacity will increase slightly. As more bags slowly begin to fail over hours or days, the opacity continues to increase. Complete failure is not immediate. The operators have ample time to take corrective action.

The proposed malfunction bypass procedure for Boiler No. 3* is:

1. Warm up Boiler No. 2 (natural gas) and bring unit on-line with flue gas flowing through and warming Boiler No. 2 spray dryer, baghouse, and induced fan.
2. Reduce the load on Boiler No. 3 to minimum firing rate and increase the load on Boiler No. 2.
3. Quickly switch the natural gas combustion flue gas for Boiler No. 2 from Boiler No. 2 induced draft fan to Boiler No. 2 auxiliary induced draft fan.
4. Change flue gas flow from Boiler No. 3 spray dryer and baghouse to Boiler No. 2 spray dryer and baghouse and allow system to warm up for 15 minutes without feeding chemicals to spray dryer.
5. After 15 minutes of Boiler No. 2 spray dryer and baghouse warm-up, begin feeding chemicals to spray dryer.
6. After 1-½ hr of feeding chemicals to Boiler No. 2 spray dryer, increase the load on Boiler No. 3 and decrease the load on Boiler No. 2 for shutdown.

Table 11 (condensed from Table E6) summarizes emission rates over the 3-hr changeover with new air heater combustion air bypass ductwork. This proposed plant modification is discussed in the following chapter (as Options A and B). Figures D9 and D10 show diagrams of flue gas flow during this operation.

The particulate, nitrogen oxides, and sulfur oxides emission limits are all in compliance during a baghouse or SDA malfunction. In the event of a boiler malfunction, such as loss of a coal feeder, the nitrogen oxides emissions may increase to 1.0 lb/MMBtu and the boiler will be out of compliance. This is due to the inability of immediately switching to natural gas fuel and reducing coal combustion emissions. In Option A, an existing rear wall burner is in Boiler No. 1 only; the boiler must be shut down and cooled to change over from coal to natural gas firing. Option B specifies a new sidewall burner in Boiler No. 1 and Boiler No. 3, but this burner is retracted during coal operation. The ability to dual-fire completely on natural gas would take a minimum of 1 hr.

*This procedure can also be used for Boiler No. 1 burning coal.

Option C includes two sidewall burners (which are not retracted) in Boilers No. 1 and No. 3. During a coal feeder malfunction, the burners can immediately be turned on while the coal feeding is stopped. This is the only option where compliance can be achieved at all times.

Table 11. Summary of estimated emission rates during a malfunction at the CFHP for Options A and B.

Type of Emission	USEPA Permit Limits	Plant Operational Range of Emissions
Particulate		
lb/hr	4.0	0.47
Opacity, %	20%	5%
Nitrogen oxides		
lb/MMBtu heat input	0.50	0.35
lb/hr	53.0	8.26
Sulfur oxides		
lb/MMBtu heat input	0.32	0.18 to 0.28
lb/hr	33.9	4.25 to 6.61

3 Plant and Operation Modifications Analysis

The different methods reviewed in this study were evaluated for acquisition costs, implementation costs, and projected emissions. Appendix G provides detailed construction cost estimates for:

- opacity monitor modifications for all options
- combustion air revision
- demolition
- structural roof
- new flue gas breeching (control dampers, isolation dampers & expansion joints)
- one new sidewall burner for Boilers No. 1 and No. 3
- two new sidewall burners for Boilers No. 1 and No. 3.

Explanation of Life-Cycle Costs

Life-cycle costing for the existing operation and options was performed using WinLCCID Version 1.6 Build 58. Energy costs were escalated using the rates in the program that were taken from NIST Handbook 135 Supplement (April 1999). Labor and other operating costs were escalated using an inflation factor of 2.5 percent/year. Future costs were reduced to their present value equivalents using the programs discount rate of 2.85 percent. Appendix H outlines the life-cycle cost analysis for the revised operation.

Existing Operation Summary

This is the "status quo" option, with the exception of opacity monitor modifications. Fuel usage and the other operating costs were taken from plant records for the year 2000. The only capital expenditure cost is for modifying the opacity monitors for improved accuracy. Emission rates remain unchanged; the CFHP will exceed permit limits during startup and during a malfunction of either boiler No. 1 or No. 3 if there is no bypass to the air heater.

Opacity monitors are installed on the exhaust stacks associated with Boilers No. 1, No. 2, and No. 3. The opacity monitor associated with Boiler No. 2 is an older model and will be replaced to match the monitors installed for Boilers No. 1 and No. 3. These monitors are located downstream of the baghouse and induced draft fan in the stack at the test port location (platform). With the exception of Boiler No. 2, these instruments were installed recently (1999) and replaced similar instruments in the same weatherproof enclosures. Malmstrom AFB has been experiencing opacity exceedances that occur when fog is present. Researchers noted that these exceedances may be unrelated to flue gas opacity, but may instead be due to fogging on the mirrors and other optical surfaces within the opacity analyzers. The analyzer manufacturer has confirmed that this may occur when water vapor is drawn into the instrument through the purge air intake. This explanation is supported by the fact that the purge air blowers on these units are unheated.

To reduce or eliminate these apparent exceedances, the purge air must be free of significant amounts of water vapor or entrained moisture. In addition, the purge air and the analyzer surfaces should be heated so that the optical surfaces do not reach a temperature relatively low enough for condensation. These recommended changes should help to accomplish this:

1. The weatherproof enclosures must be properly sealed to eliminate the entrance of water, insulated, and heated using self-limiting electrical heat tape. This will keep the electronics package as well as the light source, receiver and mirror package at a temperature high enough to prevent condensation.
2. The purge air inlet should be extended down through the roof. The existing filter should be examined to verify that it is within specification. (The filter media should reject particles larger than 10 microns.) The filter should also be installed at an accessible location within the boiler plant. All purge air piping above the roof level should be insulated.

Tables 12 and 13 summarize the costs and emissions compliance outcome for the "status quo" option.

Revised Plant Operation with Combustion Air System Modifications

The flue gas temperature at the air heater outlet of the HTHW boiler is too low. The air heater outlet flue gas temperatures are 50 °F below the original manufacturer's predictions. Prior test data shows that the air heater outlet flue gas temperature ranges from 310 °F at full boiler load to 245 °F at minimum boiler load when firing coal.

Table 12. Cost summary for "status quo" option.

Equipment / Materials / Parameters	Cost
Capitol cost	
Opacity monitor modifications not including engineering	$105,800
Operating costs per year	
Fuel	
Coal (5,500 tons @ $72.00/ton)	$396,012
Natural gas (156,868 MCF @ $0.89/therm)	$1,242,551
Operating and maintenance labor	$845,000
Ash disposal	$54,058
Maintenance material	$90,000
Electrical power (boiler system only)	$18,659
Lime	$5,142
Total operating costs	$2,651,422
Life cycle cost (25 years)	$55,601,084

Table 13. Emission compliance summary for "status quo" option.

Emission Compliant	Startup	Shutdown	Malfunction
Opacity	Noncompliant	Compliant	Noncompliant
Particulate	Noncompliant	Compliant	Noncompliant
NOx	Noncompliant	Compliant	Noncompliant
SO_2	Noncompliant	Compliant	Noncompliant

Removal of SO_2 using the spray dryer is optimized when the flue gas temperature is greater than 300 °F. The current plant operation is to burn natural gas at lower boiler loads to avoid spray dryer operational problems and ensure SO_2 emission compliance.

By modifying the combustion air system, the flue gas temperature can be controlled above 300 °F over the boiler operating range. Some of the combustion air would be bypassed around the air heater to increase the flue gas temperature to the spray dryer. The forced draft fan was sized for the additional pressure drop of a hot water coil preheater, which is not used and has been abandoned. The addition of a variable frequency drive to the forced draft fan will allow improved control of combustion air pressure at reduced boiler loads.

Modifications of the combustion air system will allow more coal to be burned at lower boiler loads. This revised plant operation would also use the opacity monitor modifications for improved accuracy. These specific plant modifications would lower overall fuel costs, but would not reduce emission limits below permit levels during startup and shutdown. Tables 14 and 15 summarize the costs and emissions compliance outcome for the plant modifications.

Table 14. Cost summary for plant modifications.

Equipment / Materials / Parameters	Cost
Capital cost	
Opacity monitor modifications	$105,800
Air heater modifications	$544,300
Total capital cost not including engineering	$650,100
Operating costs per year	
Fuel:	
Coal: 9,966 tons @ $72.00/ton	$717,561
Natural gas : 31,420 MCF @ $0.89/therm	$248,878
Operating and maintenance labor	$845,000
Ash disposal	$97,952
Maintenance material	$90,000
Electrical power (boiler system only)	$30,025
Lime	$9,316
Total operating costs	$2,038,732
Life cycle cost (25 years)	$42,706,477

Table 15. Emission compliance summary for plant modifications.

Emission Compliant	Startup	Shutdown	Malfunction
Opacity	Noncompliant	Compliant	Noncompliant
Particulate	Noncompliant	Compliant	Noncompliant
NOX	Noncompliant	Compliant	Noncompliant
SO_2	Noncompliant	Compliant	Noncompliant

Option A: 3-hr Coal Startup with Revised Breeching and Ductwork

This method would use the revised operation (Revised Plant Operation with Combustion Air System Modifications as listed above) for operating costs as well as the opacity monitor and air heater modifications. In addition, the flue gas breeching would be modified for boiler warm-up and system malfunction.

Natural gas fired Boiler No. 2 would be warmed up to temperature and brought on-line. The high temperature hot water produced by Boiler No. 2 would be circulated through Boiler No. 1 or Boiler No. 3 to preheat the boiler setting prior to coal light-off. The flue gases from Boiler No. 2 would be ducted to the spray dryer and baghouse of Boiler No. 1 or Boiler No. 3 to preheat them prior to startup. This will greatly reduce the time required to bring the system up to temperature for spray dryer operation.

This same flue gas breeching would be used in the event of a malfunction of the spray dryer or baghouse on Boiler No. 1 or Boiler No. 3. The boiler operators have a 2 to 3 hr time period from when the signs of a malfunction become apparent before a malfunction actually occurs. During this time period, Boiler No. 2 would be fired to preheat the spray dryer and baghouse serving Boiler No. 2. The flue gases from Boiler No. 1 or Boiler No. 3 would then be ducted to the spray dryer and baghouse of Boiler No. 2.

Boiler No. 2 is equipped only with a natural gas burner. The proposed startup of coal fired Boiler No. 1 or No. 3 would be:

1. Circulate HTHW from Boiler No. 2 (natural gas) through the proposed coal fired boiler (Boiler No. 3 for example) for 5 hr or more. The pressure parts in Boiler No. 3 will increase to 350 °F.
2. Increase the natural gas combustion on Boiler No. 2 to 38 MMBtu/hr heat input (100 percent capacity). The time of this combustion is 1 hr or more.
3. Through interconnecting breeching cause the natural gas flue gas at 320 °F from Boiler No. 2 to flow through the spray dryer, baghouse, and induced draft fan of Boiler No. 3. This hot (320 °F) flue gas will heat up the spray dryer, baghouse, breeching and induced draft fan of Boiler No. 3. The time for this natural gas combustion warmup will be 2 hr or more.
4. The first hour of coal combustion of Boiler No. 3 will also include natural gas combustion from Boiler No. 2. The combined flue gas from Boiler No. 3 and Boiler No. 2 will flow through the spray dryer, baghouse, breeching, and induced draft fan of Boiler No. 3.

Table 16 lists the emission rates during the 1st hour of startup for Option A. (All emissions are in compliance.)

The second and third hour of coal combustion of Boiler No. 3 will also include natural gas combustion from Boiler No. 2. The combined flue gas from Boiler No. 3 and Boiler No. 2 will flow through the spray dryer, baghouse, breeching, and induced draft fan of boiler No. 3. Table 17 lists a summary of emission rates during the 2d and 3d hours of startup for Option A. Figures D11 through D15 show diagrams of flue gas flow during this operation. Tables 18 and 19 summarize the costs and emissions compliance outcome for the Option A.

Table 16. Summary of estimated emission rates during 1st hour startup for Option A.

Type of Emission	USEPA Permit Limits	Plant Operational Range of Emissions
Particulate		
lb/hr	4.0	0.50
Opacity, %	20%	5% or less
Nitrogen oxides		
lb/MMBtu heat input	0.50	0.33
lb/hr	53.0	19.70
Sulfur oxides		
lb/MMBtu heat input	0.32	0.100
lb/hr	33.9	5.93

Table 17. Summary of estimated emission rates during 2[d] and 3[d] hour startup for Option A.

Type of Emission	USEPA Permit Limits	Plant Operational Range of Emissions
Particulate		
lb/hr	4.0	0.606 to 0.676
Opacity, %	20%	5%
Nitrogen oxides		
lb/MMBtu heat input	0.50	0.26 to 0.23
lb/hr	53.0	15.80 to 17.05
Sulfur oxides		
lb/MMBtu heat input	0.32	0.075 to 0.080
lb/hr	33.9	4.81 to 5.44

Table 18. Cost summary for Option A.

Equipment / Materials / Parameters	Cost
Capital cost	
Opacity monitor modifications	$ 105,800
Air heater modifications	$ 544,300
Breeching modifications	$ 1,000,200
Demolition of existing breeching	$ 135,500
Structural supports	$ 234,900
Total capital cost not including engineering	$ 2,020,700
Operating costs per year	
Fuel:	
Coal: 9,966 tons @ $72.00/ton	$ 717,561
Natural gas: 31,420 MCF @ $0.89/therm	$ 248,878
Operating and maintenance labor	$ 845,000
Ash disposal	$ 97,952
Maintenance material	$ 90,000
Electrical power (boiler system only)	$ 30,025
Lime	$ 9,316
Total operating costs	$ 2,038,732
Life Cycle Cost (25 years)	$44,077,077

Table 19. Emission compliance summary for Option A.

Emission Compliant	Startup	Shutdown	Malfunction
Opacity	Compliant	Compliant	Compliant
Particulate	Compliant	Compliant	Compliant
NOX	Compliant	Compliant	Noncompliant
SO_2	Compliant	Compliant	Compliant

Startup estimated emission rates are listed in Table E7. This option provides permit compliance for startup, operation at all operating loads, shutdown, and malfunction of the baghouse or SDA. A malfunction of the boiler will cause the plant to exceed nitrogen oxide emission limitations.

Option B: 3-hr Coal Startup with New Burner

Option B uses the same operating costs as the revised operation (Revised Plant Operation of Combustion Air System) and the capital costs of Option A with the addition of new natural gas burners for Boilers No. 1 and No. 3.

Boiler No. 1 is equipped with a 38 MMBtu/hr heat input existing burner located in the rear wall. This burner is much too large to be used as a startup burner and requires the grate and coal feeders to be bricked over to prevent overheating from the burner radiant heat. To burn coal, the grate and feeders have to be unbricked and a refractory plug installed over the burner. This plug is required to protect the burner from the coal-firing radiant heat, as the burner has no provision for cooling air. The changeover from coal to natural gas firing takes an 8-hr shift after the boiler has cooled down.

The proposed option is to install a single natural gas-fired, 25 MMBtu/hr heat input, burner in the sidewall of Boilers No. 1 and No. 3. This burner will allow the startup of Boilers No. 1 and No. 3 without using Boiler No. 2. The boiler sidewall tubes would be bent for burner clearance. The burner would have a retractable mounting for refractory plug installation from outside the boiler when firing coal and would not require that the grate and coal feeders be bricked.

The breeching modifications would allow the flue gases from Boiler No. 1 or Boiler No. 3 to be ducted to the spray dryer and baghouse of Boiler No. 2 in the event of a malfunction.

Boilers No. 1 and No. 3 would each have proposed small natural gas burners of 25 MMBtu/hr heat input. The proposed startup of boiler No. 3 is:

1. Circulate HTHW from Boiler No. 2 (natural gas) through Boiler No. 3 for 5 hr or more. The pressure parts in Boiler No. 3 will increase to 350 °F.
2. Warm up Boiler No. 3 with 10 MMBtu/hr heat input with the natural gas burner only. This warm-up is for the mechanical dust collector and air heater, bypassing the spray dryer and baghouse of Boiler No. 3. This warm-up is for an hour or greater. All environmental limits are in compliance.
3. Continue to warm up Boiler No. 3, increasing the heat input to 25 MMBtu/hr with natural gas only. The flue gas flow will now be through the spray dryer, baghouse, breeching, and induced draft fan of Boiler No. 3. This warm-up is for 2 additional hours (2d & 3d hours). The chemical feed to the spray dryer can be started at the end of the 3d hour. All environmental limits are in compliance.
4. The first 3 hr of coal combustion will also include the natural gas burner operation to ensure adequate flue gas temperature to the spray dryer for sulfur oxide removal.

Table 20 summarizes the estimated emission rates over the first 3 hours of coal combustion. (All emissions are in compliance all the time.) Figures D16 through D19 provide diagrams of flue gas flow during this operation.

Startup emission rates are listed in Table E8. This option provides permit compliance for startup, operation at all loads, shutdown, and malfunction of the baghouse or SDA. A malfunction of the boiler will probably cause the plant to exceed nitrogen oxides emission limitations. Tables 21 and 22 summarize the costs and emissions compliance outcome for the Option B.

Table 20. Summary of estimated emissions during startup for Option B.

Type of Emission	USEPA Permit Limits	Plant Operational Range of Emissions
Particulate		
lb/hr	4.0	0.464 to 0.640
Opacity, %	20%	5%
Nitrogen oxides		
lb/MMBtu heat input	0.50	0.42 to 0.27
lb/hr	53.0	17.30 to 13.40
Sulfur Oxides		
lb/MMBtu heat input	0.32	0.116 to 0.099
lb/hr	33.9	4.09 to 5.780

Table 21. Cost summary for Option B.

Equipment / Materials / Parameters	Cost
Capital cost	
Opacity monitor modifications	$105,800
Air heater modifications	$544,300
Breeching demolition	$135,500
Breeching structural supports	$234,900
Breeching modifications	$1,000,200
New sidewall burners	$530,200
Total capital cost not including engineering	$2,550,900
Operating costs per year	
Fuel:	
Coal: 9,966 tons @ $72.00/ton	$717,561
Natural gas: 31,420 MCF @ $0.89/therm	$248,878
Operating and maintenance labor	$845,000
Ash disposal	$97,952
Maintenance material	$90,000
Electrical power (boiler system only)	$30,025
Lime	$9,316
Total operating costs	$2,038,732
Life cycle cost (25 years)	$44,607,277

Table 22. Emission compliance summary for Option B.

Emission Compliant	Startup	Shutdown	Malfunction
Opacity	Compliant	Compliant	Compliant
Particulate	Compliant	Compliant	Compliant
NOX	Compliant	Compliant	Noncompliant
SO_2	Compliant	Compliant	Compliant

Option C: Install Two Natural Gas-Fired (25 MMBtu/hr) Burners in Boilers No. 1 and No. 3

This method uses the same operating costs as the revised operation (Revised Plant Operation of Combustion Air System). The capital costs include opacity monitor modifications, combustion air modifications, and new natural gas burners for Boilers No. 1 and No. 3.

The proposed option is to install two (2) natural gas-fired, 25 MMBtu/hr heat input, burners in both Boilers No. 1 and No. 3. These burners would be installed in opposite sidewalls of the boiler and would allow the startup of Boilers No. 1 and No. 3 without using Boiler No. 2. The boiler sidewall tubes would be bent for burner clearance. The burners would have provisions for cooling air recirculating flue gas (after baghouse) and would not require a refractory plug or bricking the grate and coal feeders for operation on coal. The burners will allow each boiler to provide 40 MMBtu/hr of heat output.

The interconnecting breeching proposed in Options A and B would not be required. In the event of a Boiler No. 3 spray dryer or baghouse malfunction, the burners on Boiler No. 3 would be started to provide 40 MMBtu/hr heat output. The natural gas flue gas would travel through Boiler No. 3 spray dryer and baghouse. At the same time, Boiler No. 2 would be started and brought on-line to provide 30 MMBtu/hr heat output. The combined output of Boiler No. 3 on natural gas and Boiler No. 2 on natural gas would carry a plant load of 70 MMBtu/hr. Once Boiler No. 2 is up to load, Boiler No. 1 would be started in order to shutdown Boiler No. 3 for repairs. A malfunction of Boiler No. 1 operating on coal would follow the same sequence.

Estimated emission rates would be the same as Option B for startup and shutdown. This option provides permit compliance for startup, operation at all loads, shutdown and all baghouse, SDA or boiler malfunctions. Tables 23 and 24 summarize the costs and emissions compliance outcome for the Option B.

Table 23. Cost summary for Option C.

Equipment / Materials / Parameters	Cost
Capital cost	
Opacity monitor modifications	$ 105,800
Air heater modifications	$ 544,300
New sidewall burners	$ 1,165,700
Total capital cost not including engineering	$ 1,815,800
Operating costs per year	
Fuel:	
Coal: 9,966 tons @ $72.00/ton	$ 717,561
Natural Gas: 31,420 MCF @ $0.89/therm	$ 248,878
Operating and maintenance labor	$ 845,000
Ash disposal	$ 97,952
Maintenance material	$ 90,000
Electrical power (boiler system only)	$ 30,025
Lime	$ 9,316
Total operating costs	$ 2,038,732
Life cycle cost (25 years)	$43,872,177

Table 24. Emission compliance summary for Option C.

Emission Compliant	Startup	Shutdown	Malfunction
Opacity	Compliant	Compliant	Compliant
Particulate	Compliant	Compliant	Compliant
NOX	Compliant	Compliant	Compliant
SO_2	Compliant	Compliant	Compliant

Table 25. Summary of options with construction costs.

Option	Capital Cost, Not Including Engineering	Full Permit Compliant?
Existing operation with opacity monitor	$105,800	No
Revised plant operation of combustion air system	$544,300	No
Option A: 3-hr coal startup with revised breeching and ductwork	$2,020,700	No*
Option B: 3-hr coal startup with new burner	$2,550,900	No*
Option C: Install two natural gas-fired burners in both boilers No. 1 and No. 3	$1,815,800	Yes
*Allows for permit Compliant during all phases of operation except for a boiler malfunction.		

Table 26. Summary of options with life cycle costs.

Option	25-Year Life Cycle Cost	Full Permit Compliant?
Existing operation with opacity monitor	$55,601,084	No
Revised plant operation of combustion air system	$42,706,477	No
Option A: 3-hour coal start-up with revised breeching and ductwork	$44,077,077	No*
Option B: 3-hour coal startup with new burner	$44,607,277	No*
Option C: install two (2) natural gas-fired burners in both Boilers No. 1 and No. 3	$43,872,177	Yes
*Allows for permit Compliant during all phases of operation except for a boiler malfunction.		

Summary of Options

Tables 25 and 26 list summary information for the options presented above. The current operation is the most expensive and does not meet permit limits. Revising the plant operation of the combustion air system is the least expensive, but does not meet permit limits. Options A, B, and C have relatively the same life cycle costs. Options A and B provide permit compliance for all phases of operation, except for a boiler malfunction. Only Option C will allow full emission compliance during startup, operation, all malfunctions, and shutdown.

Other DOD/Government Coal-Fired Heat Plant Methods for USEPA Compliance

A random selection of DOD and government coal-fired heat plants was made to compare their operations and plant configurations for permit compliance with the MAFB CFHP. The following facilities were selected and results summarized in Appendix I:

- Illinois (Rock Island Arsenal)
- North Carolina (Marine Corps Base, Camp Lejeune)
- Ohio (Wright-Patterson Air Force Base)
- Texas (Red River Army Depot)
- Washington, DC (U.S. Capital Boiler Plant).

The facility manger or engineer was asked to answer a series of questions about their facility. Some of the facilities also provided copies of their operating permits. Information requested included:

- description of heat plant
- State EPA/permit requirements for startup and shutdown
- rules and requirements that may be violated during continued operation during startup and shutdown, and the associated regulated air pollutants
- facility measures taken to minimize startup emissions
- measures taken to minimize the frequency of startups.

In most cases, these facilities engage their baghouses (Camp Lejeune has an ESP) at startup to significantly reduce opacity and particulate emissions. These facilities understand that there is one disadvantage of this method, specifically, the requirement to replace the bags at least twice as often due to increased deterioration caused by acid condensate.

Each facility states that it can meet its permit requirements during all phases of operation. In Illinois, Rock Island's heating plant currently operates under an operating permit that states the operation of the boilers, in excess of the applicable emissions standards, during startup is allowed. They conclude, qualitatively, that only the CO emissions rate is violated during startup, all other emission limits are met. In North Carolina, the administrative code, NCAC Subchapter 2D, was recently amended to declare that:

> the excess emissions during startup and shutdown are in violation unless the owner or operator can demonstrate that excess emissions are unavoidable … The owner or operator shall, to the extent practicable, operate the source and any associated air pollution control equipment or monitoring equipment in a manner consistent with best practicable air

pollution control practices to minimize emissions during startup and shutdown.

In Ohio, Wright-Patterson AFB must report any excursions of the startup or shutdown provisions specified in the State's administrative code. These provisions state that the visible particulate emission limitations established in the code do not apply to "the startup and shutdown of fuel burning equipment." (See OAC rule 3745-17-07(A)(3) for details.)

In Texas, Red River Army Depot's operating permit does not specifically mention emission limitations during startup or shutdown. The Texas Administrative Code, Title 30, Part 1, Chapter 101, Subchapter A, Rule §101.7 "Maintenance, Startup and Shutdown Reporting, Recordkeeping, and Operational Requirements" has specific rules, reporting requirements, and allowances during startup and shutdown.

Finally, in Washington DC, the Capitol Heating Plant operating permit has an opacity limit for its normal operating ranges; the permit also outlines exceptions to that limit which include startup and shutdown. The particulate emissions rate for the coal-fired units is deemed to be in compliance when the flue gas is exhausted through the baghouse. Also, the NOx emission rates, based on lb/MMBtu, are both a calendar day average and 2-hour average.

In summary, the various plant permit restrictions and allowances described above appear to be fairly relaxed for startup and shutdown conditions compared to those specified in the Air Permit requirements for Malmstrom AFB's coal-fired heat plant. To meet the air quality requirements as specified by the Malmstrom AFB permit, which requires 100 percent compliance at all times, MAFB must invest approximately $2 million to complete Option C as recommended in this report.

Alternative Methods to Coal for Providing Heat

CERL will also complete a HeatMap analysis of MAFB and publish the report separately. The objective of the study is to develop, analyze, and recommend alternative methods for providing heat to Malmstrom AFB while maintaining compliance with all applicable environmental permits and regulations.

4 Conclusions and Recommendations

Conclusions

This study concludes that:

1. Qualitatively, the MAFB CFHP currently exceeds its permit limits during startup and malfunction.
2. Qualitatively, that the MAFB CFHP will be able to meet its current permit limits through equipment modifications and operational changes.
3. Revisions to the Montana SIP or the MAFB CFHP operating permit will not be necessary if the recommendations of this study or of the HEATMAP analysis are implemented. These recommendations include the implementation of one of three options:
   a. Option A: 3-hr coal startup with revised breeching and ductwork
   b. Option B: 3-hr coal startup with new burner
   c. Option C: Install two natural gas-fired (25 MMBtu/hr) burners in both Boilers No. 1 and No. 3.
4. The MAFB CFHP can meet its permit limits during startup, shutdown, and malfunctions of the SDA and/or baghouse if operational and equipment changes are made using either Options A or B.
5. The MAFB CFHP can to meet its permit limits during startup, shutdown and ***all malfunctions*** if operational and equipment changes are made using Option C.
6. One alternative to adopting Option A, B, or C, would be for the command to pursue a change to the Montana SIP and/or their CFHP operating permit.
7. Sulfur oxides can be reduced significantly to 0.18 lb/MMBtu heat input or 4.25 lb/hour to 16.92 lb/hour over the boiler operating range if some of the combustion air is allowed to bypass the air heater and increase the flue gas temperature to the spray dryer. The constant flue gas temperature of 320 °F to the spray dryer will allow additional feed of calcium hydroxide ($Ca(OH)_2$) to the spray dryer and reduce the sulfur oxide emissions.
8. A final alternative to would be to continue operating according to the status quo (do nothing), make no operational or capital improvement changes, and allow

both the USEPA and MDEQ to exercise enforcement discretion of their air quality regulations.

Recommendations

This study recommends:

1. *Implementation of Option C*. This has the lowest life-cycle costs and will allow the CFHP to be in compliance during startup, normal operation, all malfunctions and shutdown.
2. *System enhancements to lower sulfur oxide emissions*. This change should only be pursued if agreed to in writing between the State of Montana, the USEPA, and Malmstrom AFB. (Note that this is not a design change, only an enhancement of the existing design for increased sulfur oxide removal, which would represent:
    a. Lower sulfur oxides emissions for MDEQ
    b. Lower operating cost for MAFB, i.e., more coal usage and less natural gas usage.
3. *Opacity monitor modifications* (even if no action is taken to implement any of the options or recommendations). The modifications are required to increase the accuracy of the opacity monitor at all times.
4. *Complete air heater modifications* (even if no action is taken to implement any of the other options or recommendations). This will allow the burning of less expensive coal fuel at lower boiler loads and decrease SO_2 emissions.

Appendix A: Summary of Emission Limits Imposed by USEPA, MDEQ, and MAFB's Permit

40 CFR-50-A, J and F are test methods for ambient air quality. The NAAQS limits in ppm cannot be directly converted to lb/MMBtu. The μg/m^3 and ppm ground level concentrations are calculated using a dispersion modeling program, flue gas flow, flue gas temperature, building dimensions, stack height and stack emissions in grams/second.

The New Source Performance Standards (NSPS) are in 40 CFR Part 60 Subpart D for heat inputs greater than 100 MMBtu/hr and less than 250 MMBtu/hr. Particulate is 0.05 lb/MMBtu, opacity is 20 percent, NOX is 0.60 lb/MMBtu and SO2 is a 90 percent reduction of potential and 1.2 lb/MMBtu. For MAFB, this would calculate to 5.3 lb/hr particulate, 63.6 lb/hr of NOX and 127.2 lb/hr of SO2.

Federal/State/Permit Limits

(lb/hr)				
	Particulates PM_{10}	**Opacity**	**SO_2**	**NOx**
Federal Regulations NSPS	5.3	Less than 20% averaged over 6 consecutive minutes	127.2	63.6
USEPA (NAAQS - permissible level of air contaminant in the ambient air)	50 μg/m^3 (Annual Arithmetic Mean)	None	0.03 ppm (Annual Arithmetic Mean) (80 μg/m^3)	0.053 ppm (Annual Arithmetic Mean) (100 μg/m^3)
MDEQ ARM 17.8	43.05 (ARM 17.8.310)	Less than 20% averaged over 6 consecutive minutes (ARM 17.8.304)	106.0	None listed in ARM.17.8
MAFB Permit	4.0	Less than 20% averaged over 6 consecutive minutes	33.90	53.0

(lb/MMBtu)				
NSPS	0.05	Less than 20% averaged over 6 consecutive minutes	1.2	0.60
MDEQ (ARM 17.8)	0.41 (ARM 17.8.309)	Less than 20% averaged over 6 consecutive minutes	1.0 (ARM 17.8.322)	None listed in ARM.17.8
MAFB Permit	None Listed	Less than 20% averaged over 6 consecutive minutes	0.32	0.50
Notes: The emissions limitation is 1.0 lb sulfur/MMBtu-fired, and using the *design maximum* heat rate is 106.0 MMBtu/hr. Emissions referenced in ARM 17.8.322(4). (Sulfur gaseous fuel not calculated.)				

Appendix B: Summary of MAFB's February 2001 Emissions Test

Boiler No. 1	Emission Limits	Measured Emissions
NOX	0.50 lb / MMBtu or 53.0 lb / hr	0.29 lb/MMBtu or 19.55 lb / hr
SO_2	0.32 lb / MMBtu or 34 lb / hr	0.177 lb/MMBtu or 11.76 lb / hr
Particulate	4.0 lb / hr	1.047 lb/hr
Opacity	< 20 %	0.00 %
Boiler No. 2	**Emission Limits**	**Measured Emissions**
NOX	0.50 lb / MMBtu or 53.0 lb / hr	0.07 lb / MMBtu or 5.68 lb / hr
SO_2	0.32 lb / MMBtu or 34 lb / hr	N/A
Particulate	4.0 lb / hr	N/A
Opacity	< 20 %	N/A
Boiler No. 3	**Emission Limits**	**Measured Emissions**
NOX	0.50 lb / MMBtu or 53.0 lb / hr	0.35 lb / MMBtu or 25.21 lb / hr
SO_2	0.32 lb / MMBtu or 34 lb / hr	0.192 lb / MMBtu or 14.04 lb / hr
Particulate	4.0 lb / hr	1.467 lb / hr
Opacity	< 20 %	0.00 %

Appendix C: Contact List for Quantitative Startup/Shutdown (SU/SD) Emission Test Results

Name of Firm/Organization (Outside of USACE/ERDC/CERL)
Air and Waste Management Association (A&WMA)
Air Compliant Testing, Inc
American Boiler Manufactures Association (ABMA)
Coastal Air Consultants
Compliant Assurance Associates, Inc.
Council of Industrial Boiler Owners (CIBO)
Department of Energy: Clean Coal Technology
Detroit Stoker Company
Electric Power Research Institute (EPRI)
ETS, Inc.
Great Lakes Power, Ltd
Hoffman Combustion Engineering Company
IEA Coal Research, United Kingdom
Illinois Environmental Protection Agency
National Energy Technology Laboratory (NETL)
Ohio State University: Department of Mechanical Engineering
Riley Stoker Company
Schmidt Associates, Inc.
Southern Illinois University: Coal Research Center
Southern Illinois University: Department of Mechanical Engineering and Energy Processes
Spirax-Sarco, Inc.
United States Department of Energy
United States Environmental Protection Agency (to include CEMS data)
United States Environmental Protection Agency, Region 5
University of North Dakota: Department of Mechanical Engineering
Vogt – NEM Inc.
World Coal Institute

Appendix D: Flue Gas and Combustion Air Flow Drawings for Current Operations and Various Options

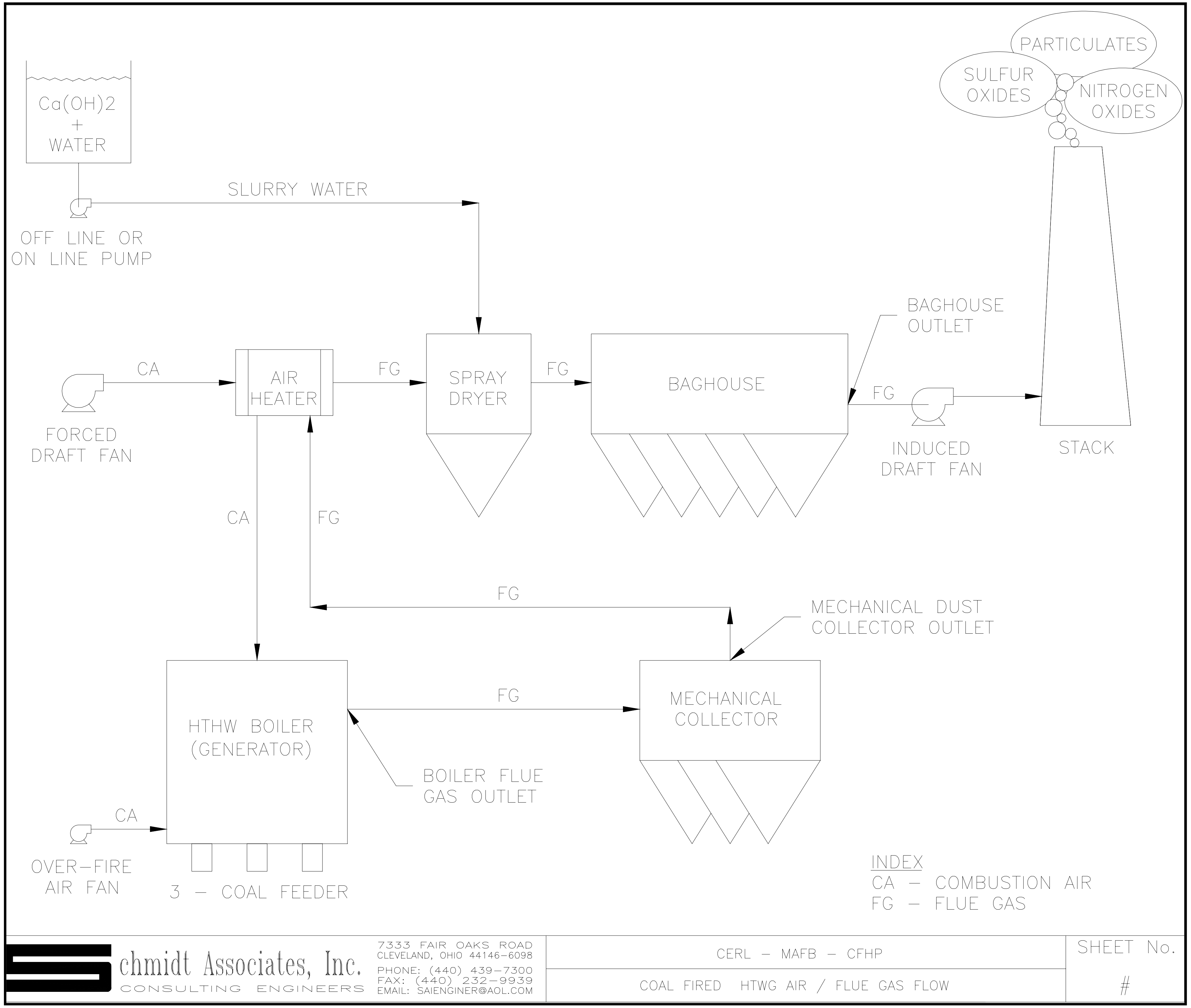


Figure D1. Coal-fired HTWG air/flue gas flow diagram.

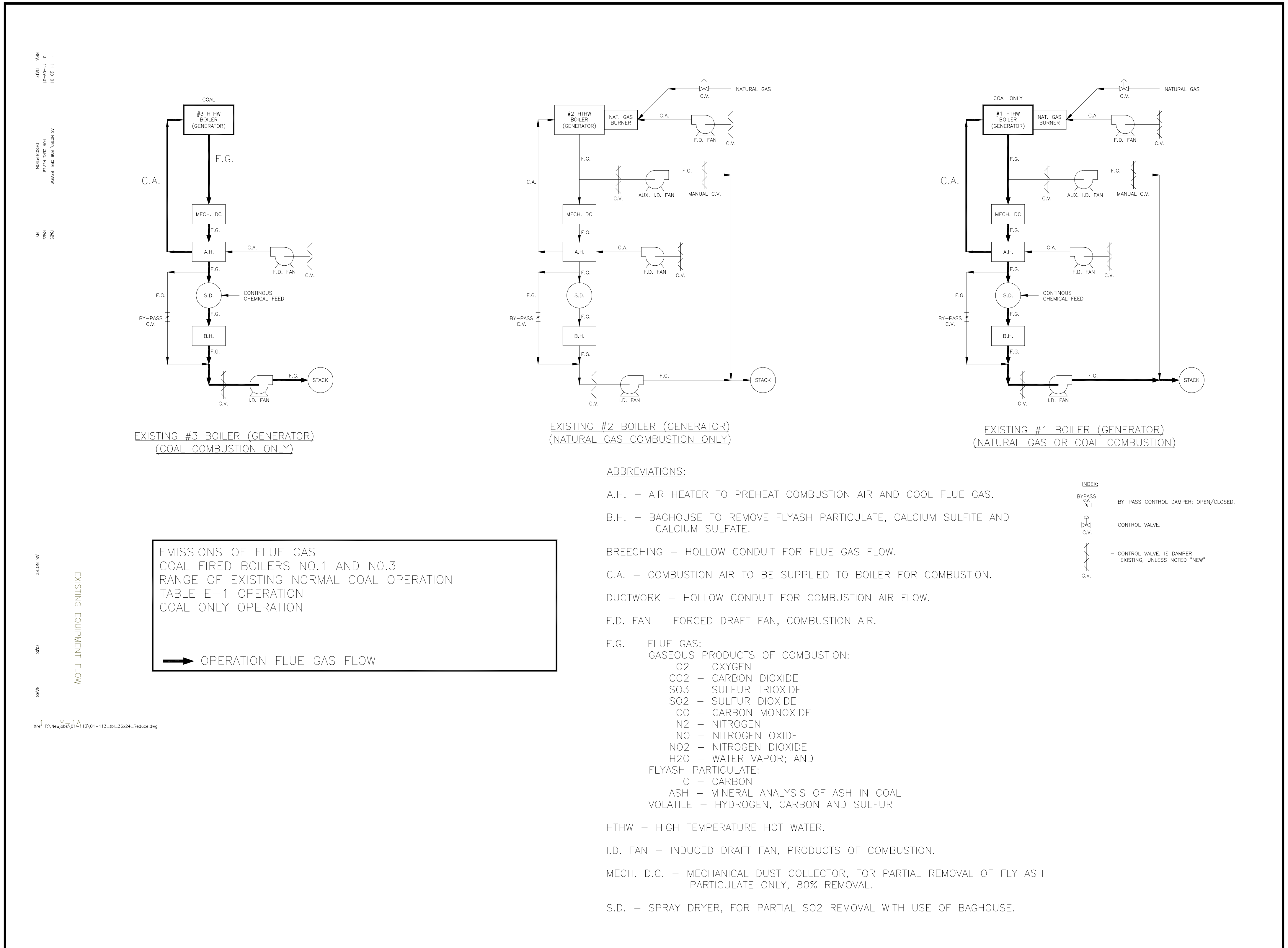


Figure D2. Flue gas flow of existing equipment for boilers No. 1 and No. 3 (coal only) during normal range of operation.

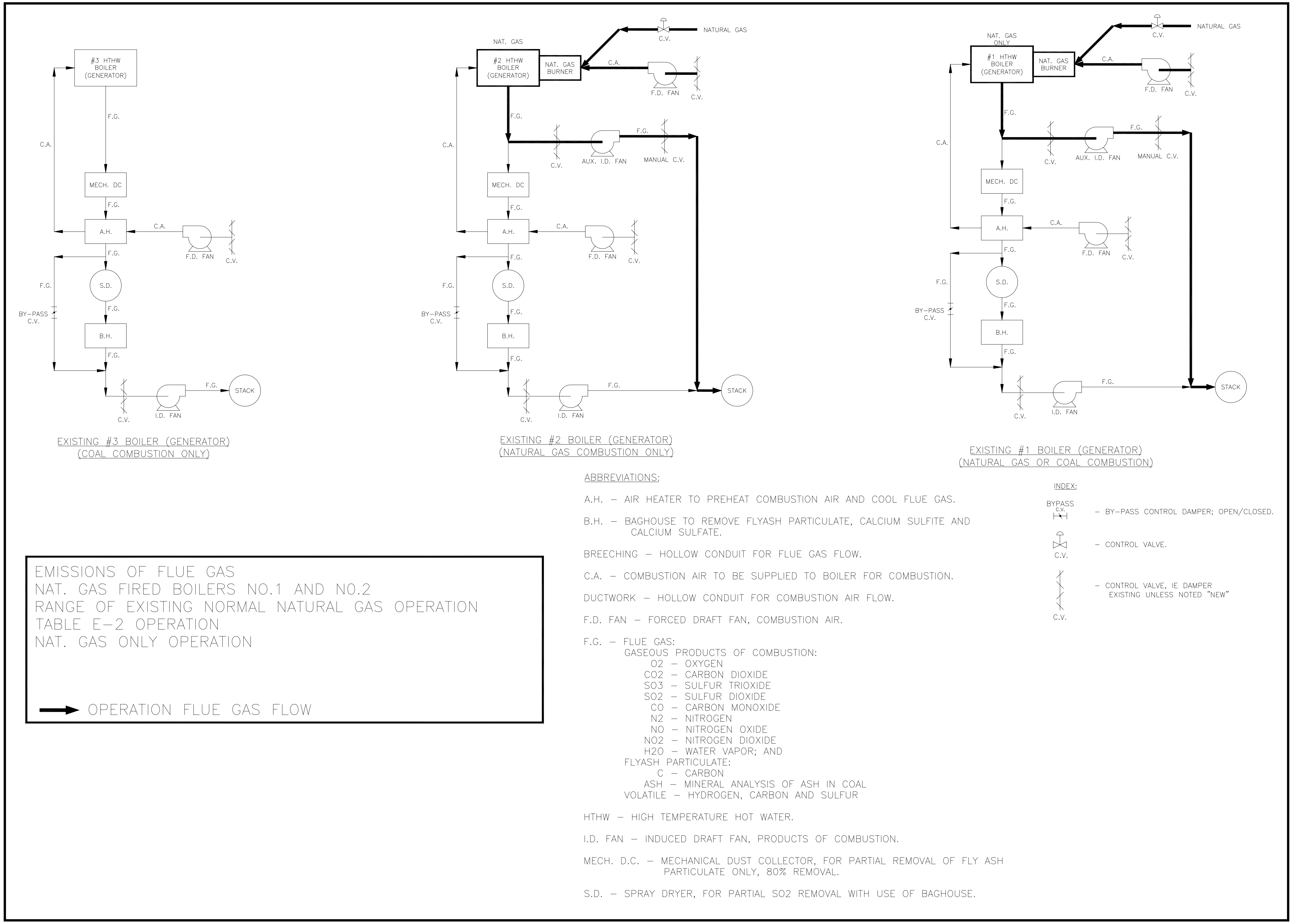
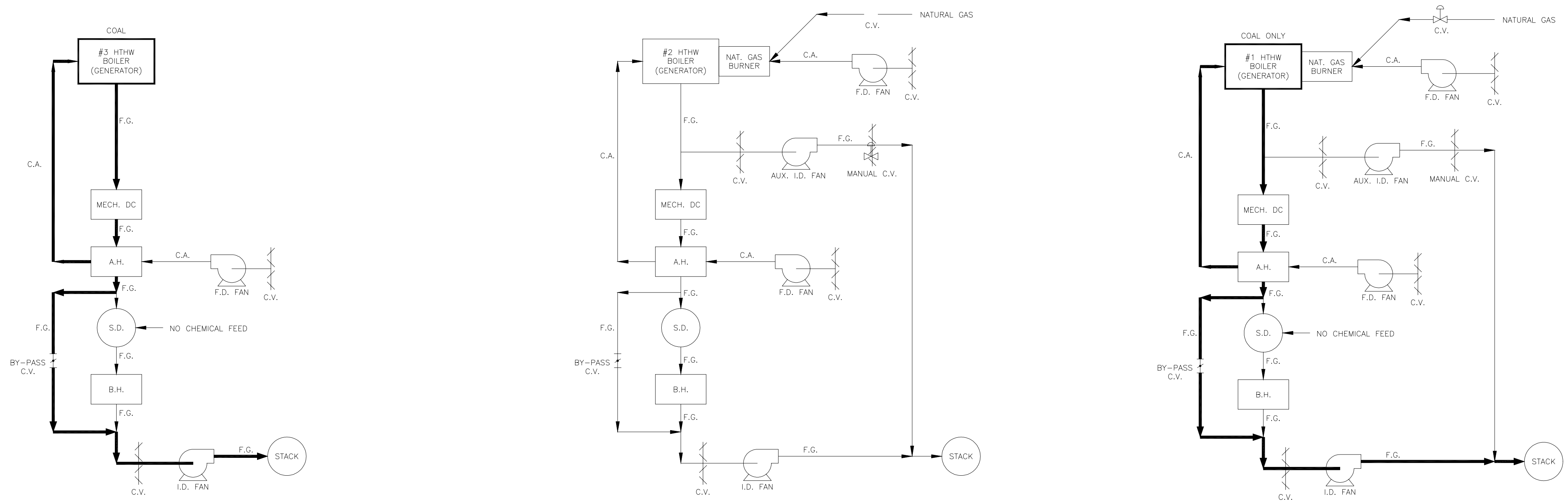


Figure D3. Flue gas flow of existing equipment for boilers No. 1 and No. 2 (natural gas only) during normal range of operation.



EXISTING #3 BOILER (GENERATOR)
(COAL COMBUSTION ONLY)

EXISTING #2 BOILER (GENERATOR)
(NATURAL GAS COMBUSTION ONLY)

EXISTING #1 BOILER (GENERATOR)
(NATURAL GAS OR COAL COMBUSTION)

EMISSIONS OF FLUE GAS
COAL FIRED BOILERS NO.1 AND NO.3
NORMAL 5 HOUR COAL START-UP OF EXISTING EQUIPMENT
(THIS IS NOT MAFB'S CURRENT OPERATIONAL STAR-UP PROCEDURE, SEE TABLE E-4. THIS IS A TYPICAL START-UP CYCLE FOR MOST COAL-FIRED BOILERS)
TABLE E-3 OPERATION
FIRST, SECOND AND THIRD HOURS OF 5 HOUR START-UP

→ OPERATION FLUE GAS FLOW

ABBREVIATIONS:

A.H. – AIR HEATER TO PREHEAT COMBUSTION AIR AND COOL FLUE GAS.

B.H. – BAGHOUSE TO REMOVE FLYASH PARTICULATE, CALCIUM SULFITE AND CALCIUM SULFATE.

BREECHING – HOLLOW CONDUIT FOR FLUE GAS FLOW.

C.A. – COMBUSTION AIR TO BE SUPPLIED TO BOILER FOR COMBUSTION.

DUCTWORK – HOLLOW CONDUIT FOR COMBUSTION AIR FLOW.

F.D. FAN – FORCED DRAFT FAN, COMBUSTION AIR.

F.G. – FLUE GAS:
GASEOUS PRODUCTS OF COMBUSTION:
O2 – OXYGEN
CO2 – CARBON DIOXIDE
SO3 – SULFUR TRIOXIDE
SO2 – SULFUR DIOXIDE
CO – CARBON MONOXIDE
N2 – NITROGEN
NO – NITROGEN OXIDE
NO2 – NITROGEN DIOXIDE
H2O – WATER VAPOR; AND
FLYASH PARTICULATE:
C – CARBON
ASH – MINERAL ANALYSIS OF ASH IN COAL
VOLATILE – HYDROGEN, CARBON AND SULFUR

HTHW – HIGH TEMPERATURE HOT WATER.

I.D. FAN – INDUCED DRAFT FAN, PRODUCTS OF COMBUSTION.

MECH. D.C. – MECHANICAL DUST COLLECTOR, FOR PARTIAL REMOVAL OF FLY ASH PARTICULATE ONLY, 80% REMOVAL.

S.D. – SPRAY DRYER, FOR PARTIAL SO2 REMOVAL WITH USE OF BAGHOUSE.

INDEX:

BYPASS C.V. – BY-PASS CONTROL DAMPER; OPEN/CLOSED.

C.V. – CONTROL VALVE.

C.V. – CONTROL VALVE, IE DAMPER
EXISTING UNLESS NOTED "NEW"

Figure D4. Flue gas flow of a typical coal-fired boiler during a 5-hour startup, 1st, 2d, and 3d hours (coal only) with existing equipment.

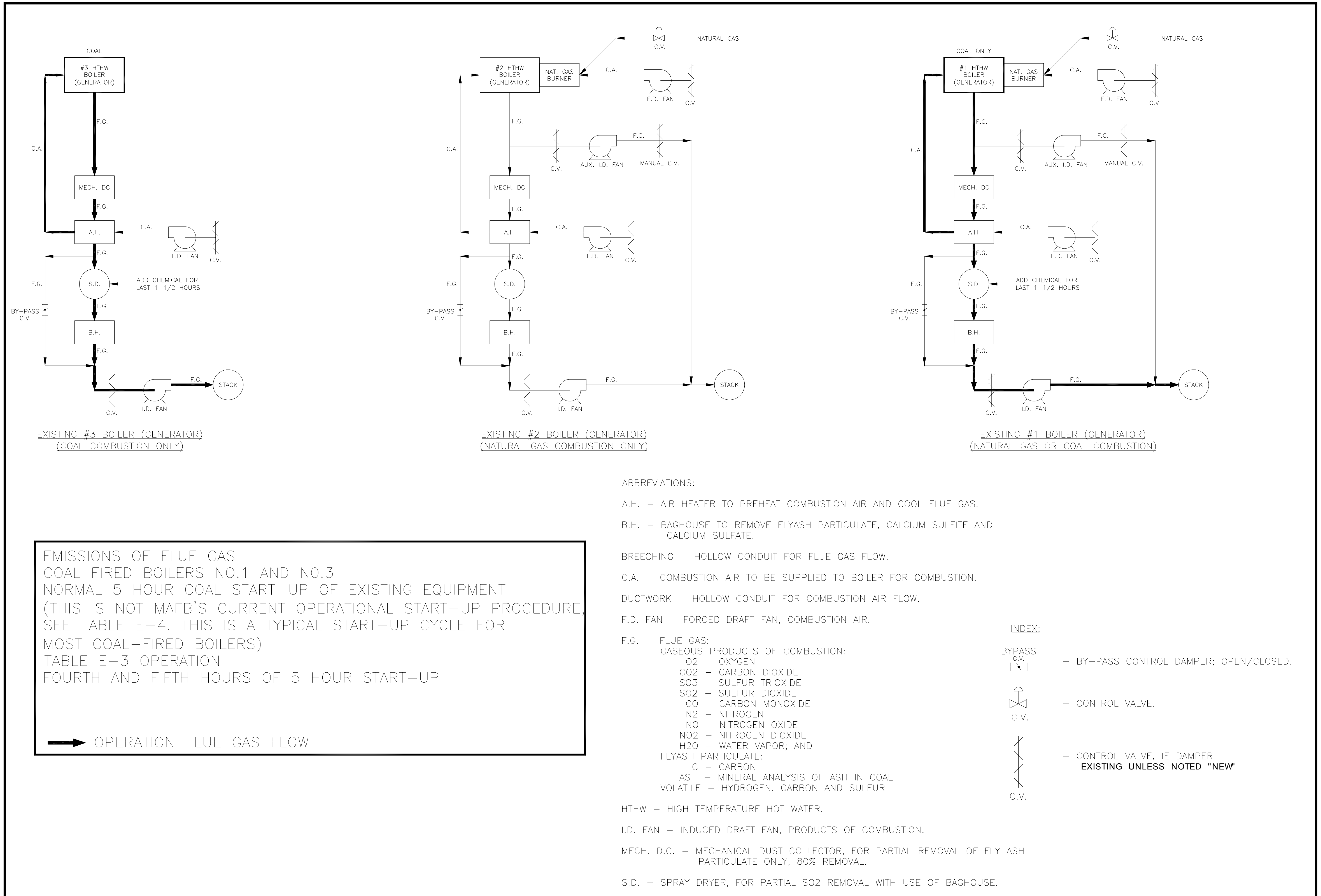
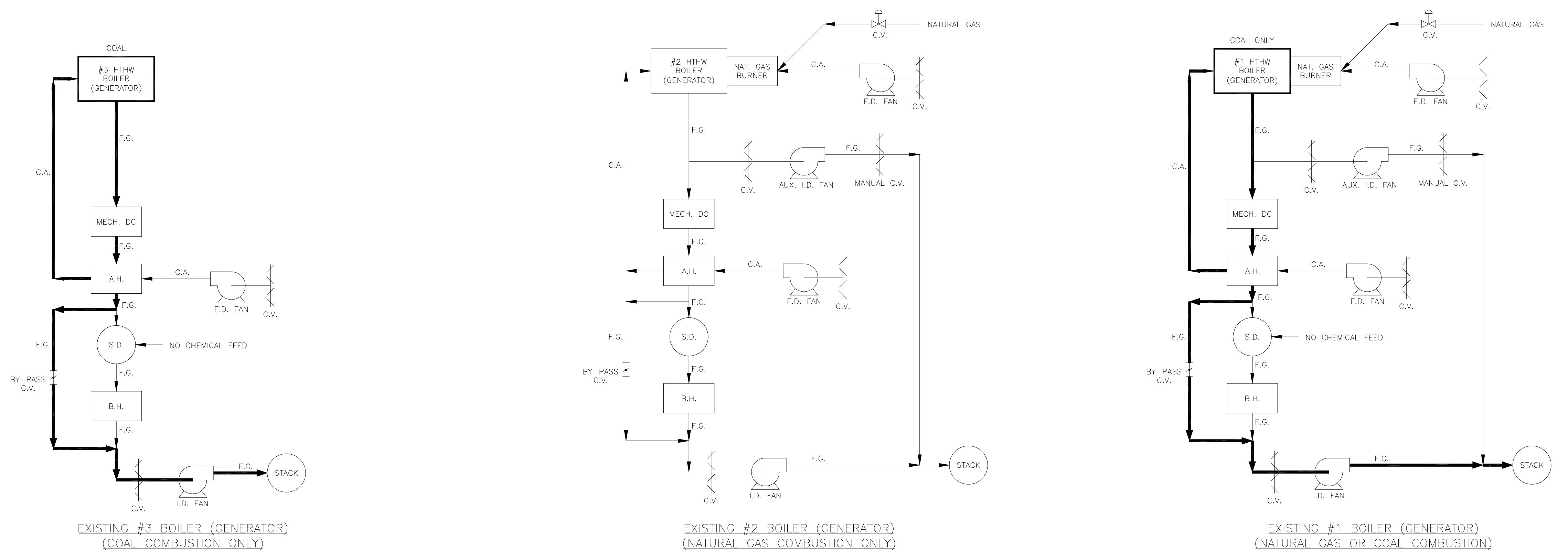


Figure D5. Flue gas flow of a typical coal-fired boiler during a 5-hour startup, 4th and 5th hours (coal only) with existing equipment.



EMISSIONS OF FLUE GAS
COAL FIRED BOILERS NO.1 AND NO.3
3 HOUR COAL START-UP OF EXISTING EQUIPMENT
(CIRCULATE HTHW FOR 5 HOURS BEFORE COAL LIGHT-OFF)
(THIS IS MAFB'S CURRENT OPERATIONAL START-UP PROCEDURE)
TABLE E-4 OPERATION
FIRST HOUR OF 3 HOUR START-UP

→ OPERATION FLUE GAS FLOW

ABBREVIATIONS:

A.H. – AIR HEATER TO PREHEAT COMBUSTION AIR AND COOL FLUE GAS.

B.H. – BAGHOUSE TO REMOVE FLYASH PARTICULATE, CALCIUM SULFITE AND CALCIUM SULFATE.

BREECHING – HOLLOW CONDUIT FOR FLUE GAS FLOW.

C.A. – COMBUSTION AIR TO BE SUPPLIED TO BOILER FOR COMBUSTION.

DUCTWORK – HOLLOW CONDUIT FOR COMBUSTION AIR FLOW.

F.D. FAN – FORCED DRAFT FAN, COMBUSTION AIR.

F.G. – FLUE GAS:
GASEOUS PRODUCTS OF COMBUSTION:
O2 – OXYGEN
CO2 – CARBON DIOXIDE
SO3 – SULFUR TRIOXIDE
SO2 – SULFUR DIOXIDE
CO – CARBON MONOXIDE
N2 – NITROGEN
NO – NITROGEN OXIDE
NO2 – NITROGEN DIOXIDE
H2O – WATER VAPOR; AND
FLYASH PARTICULATE:
C – CARBON
ASH – MINERAL ANALYSIS OF ASH IN COAL
VOLATILE – HYDROGEN, CARBON AND SULFUR

HTHW – HIGH TEMPERATURE HOT WATER.

I.D. FAN – INDUCED DRAFT FAN, PRODUCTS OF COMBUSTION.

MECH. D.C. – MECHANICAL DUST COLLECTOR, FOR PARTIAL REMOVAL OF FLY ASH PARTICULATE ONLY, 80% REMOVAL.

S.D. – SPRAY DRYER, FOR PARTIAL SO2 REMOVAL WITH USE OF BAGHOUSE.

INDEX:

BYPASS C.V. – BY-PASS CONTROL DAMPER; OPEN/CLOSED.

C.V. – CONTROL VALVE.

C.V. – CONTROL VALVE, IE DAMPER
EXISTING UNLESS NOTED "NEW"

Figure D6. Flue gas flow of MAFB's 1st hour of startup for Boilers No. 1 and No. 3 (coal only) with existing equipment.

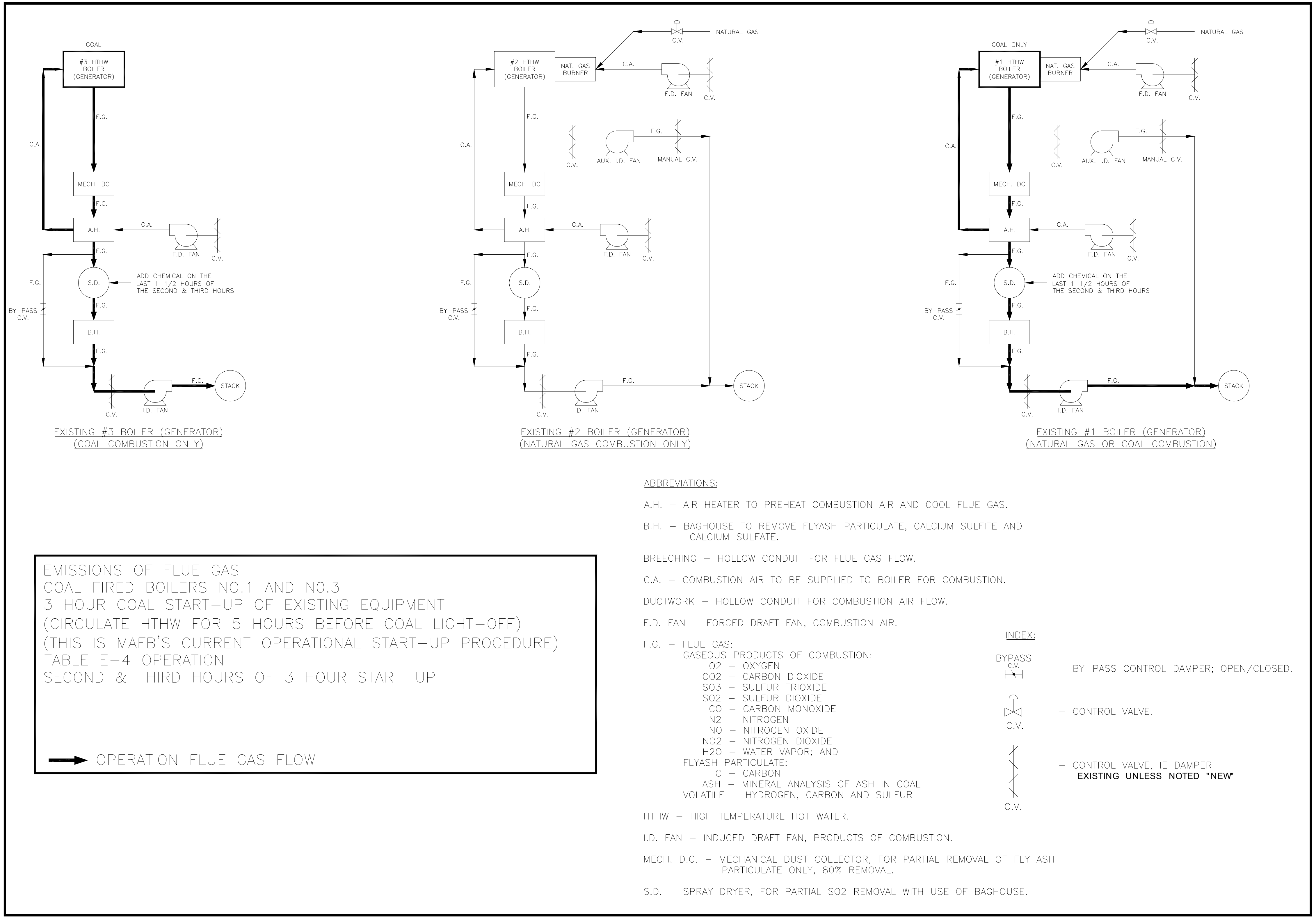


Figure D7. Flue gas flow of MAFB's 2d and 3d hours of startup for Boilers No. 1 and No. 3 (coal only) with existing equipment.

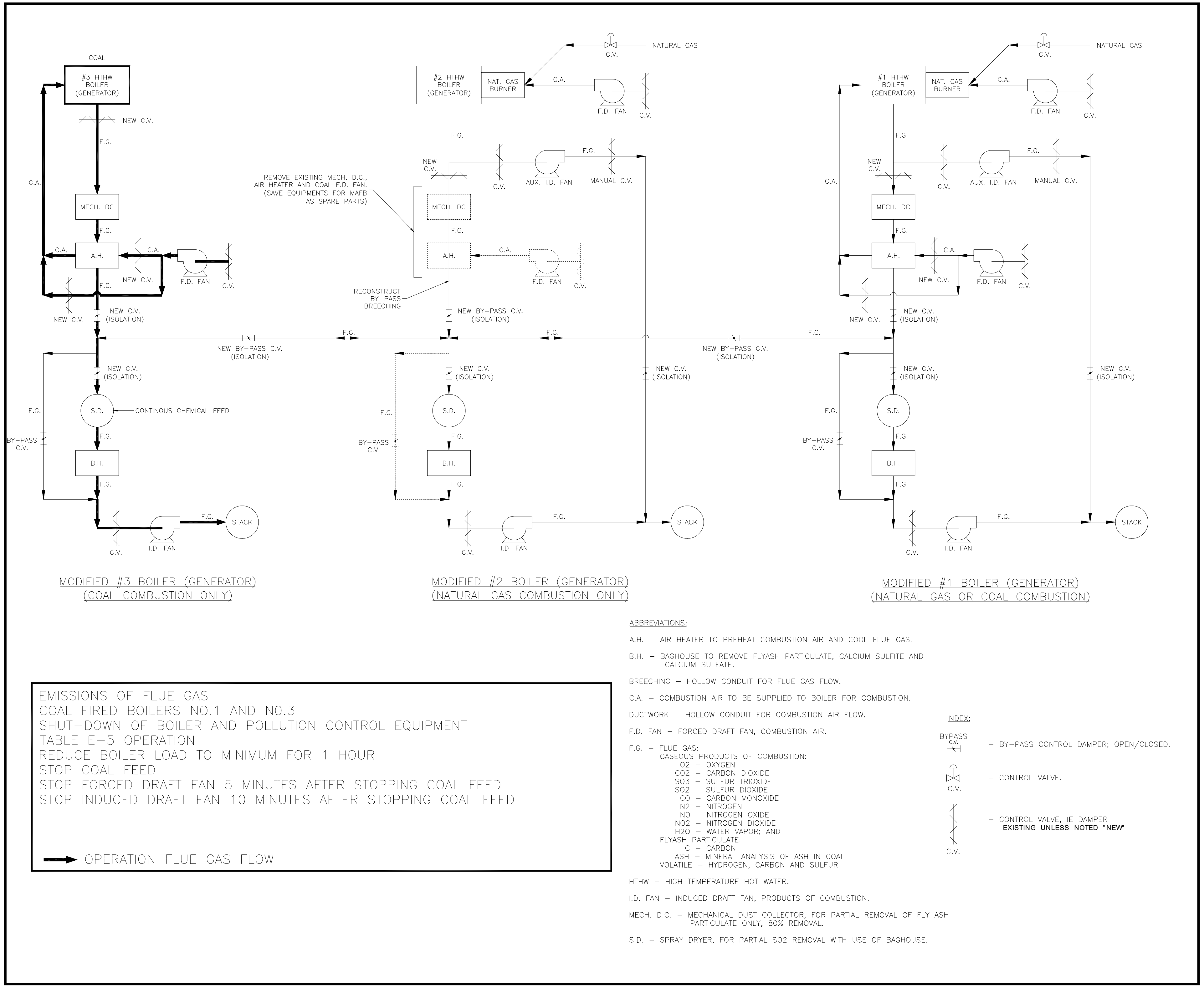


Figure D8. Flue gas flow during shutdown of existing boiler and pollution control equipment.

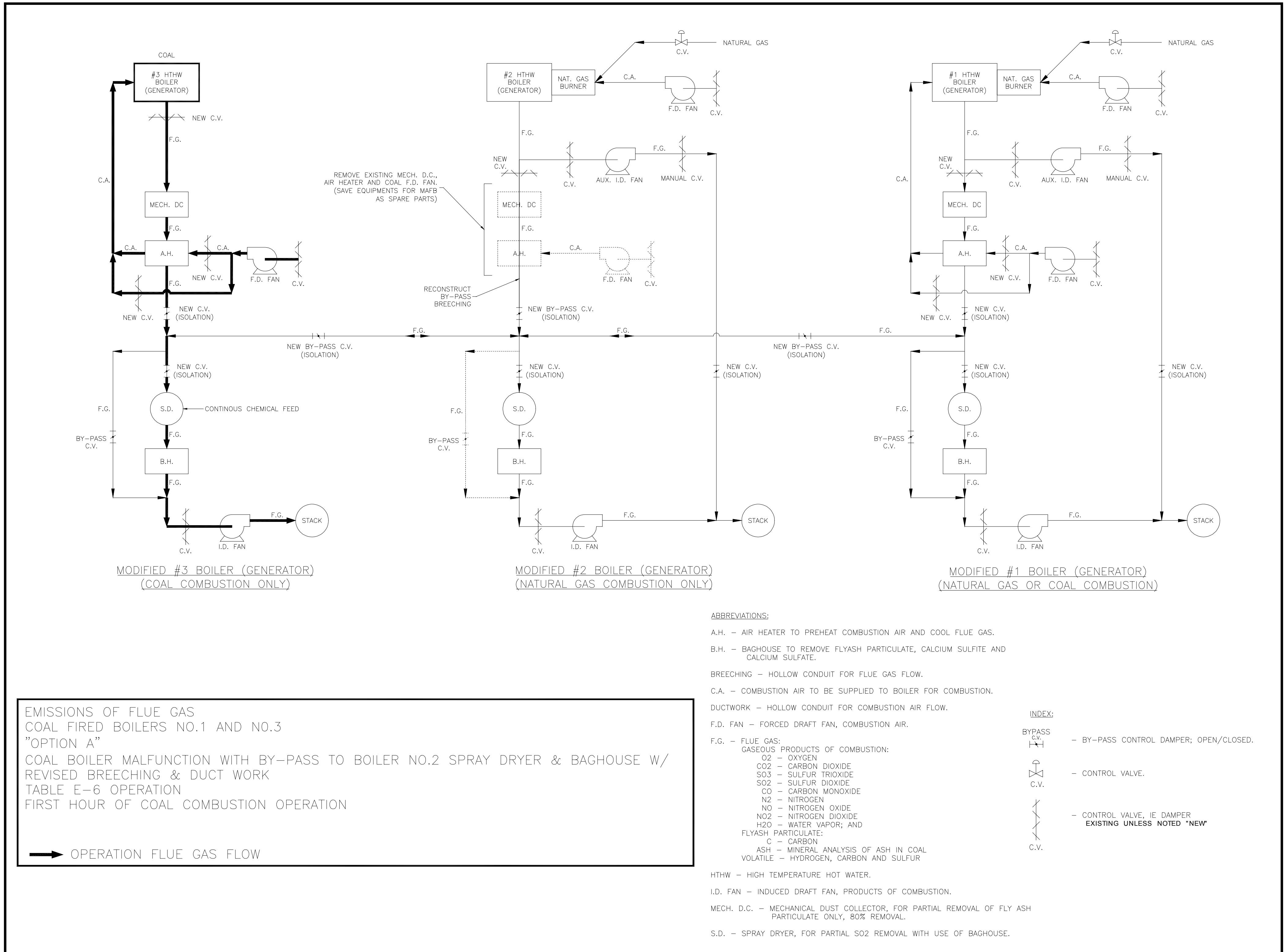


Figure D9. Flue gas flow during 1st hour of coal combustion malfunction (Boilers No. 1 and No. 3) with revised breeching and ductwork.

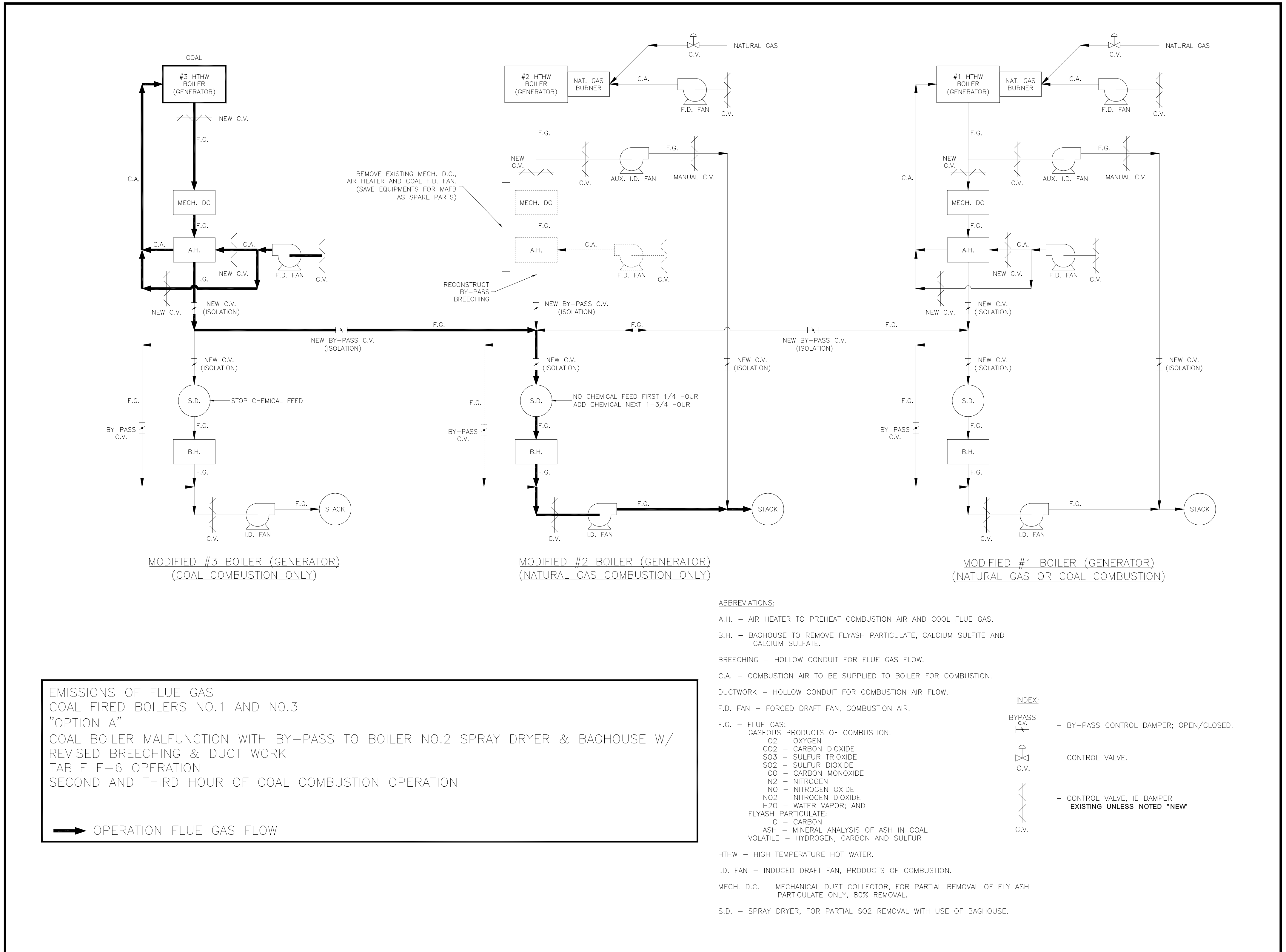


Figure D10. Flue gas flow during 2[d] and 3[d] hours of coal combustion malfunction (Boilers No. 1 and No. 3) with revised breeching and ductwork.

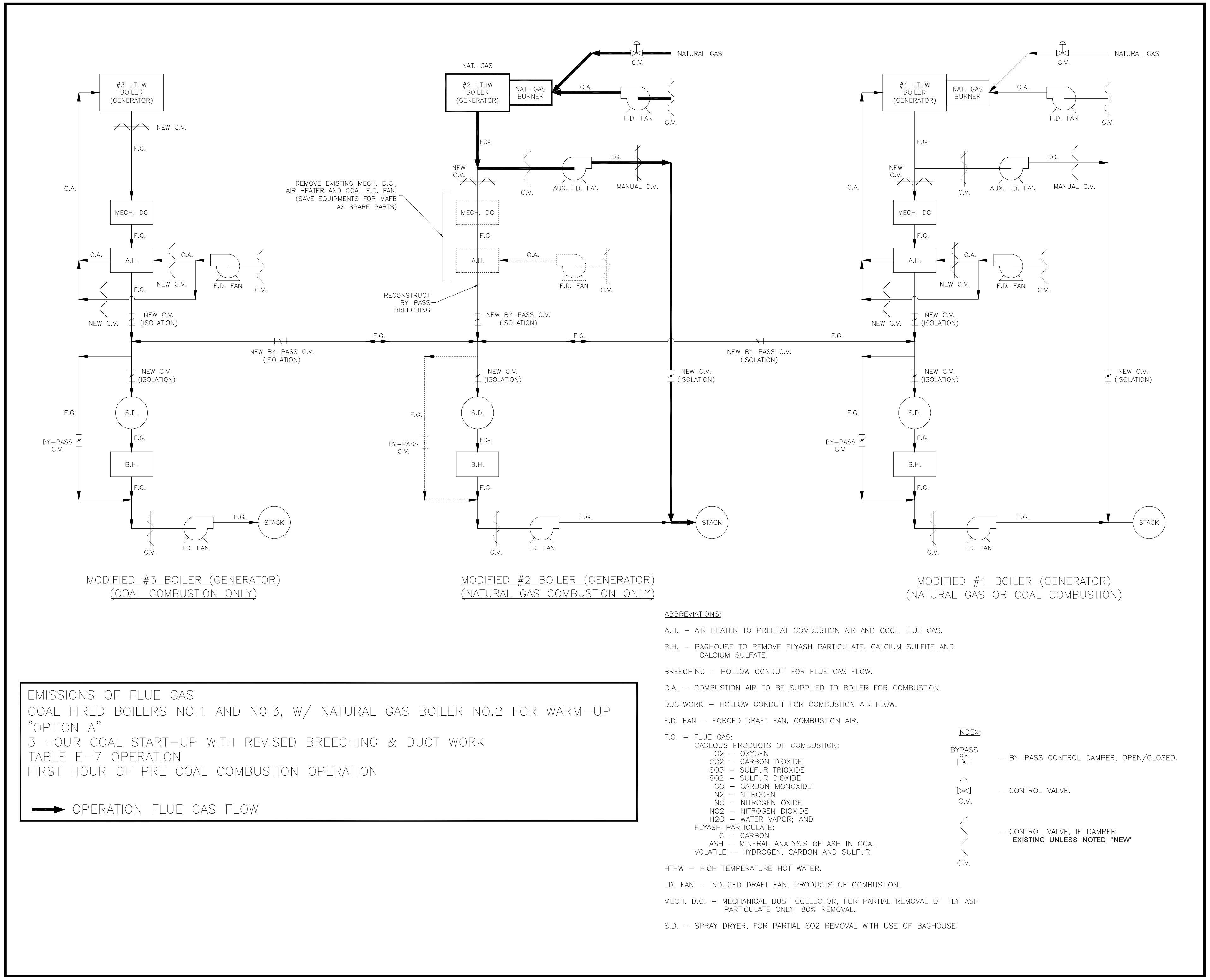


Figure D11. Flue gas flow during 1st hour of startup for Boilers No. 1 and No. 3 (No. 2 for warmup) with revised breeching and ductwork (Option "A") — first hour of pre-coal combustion.

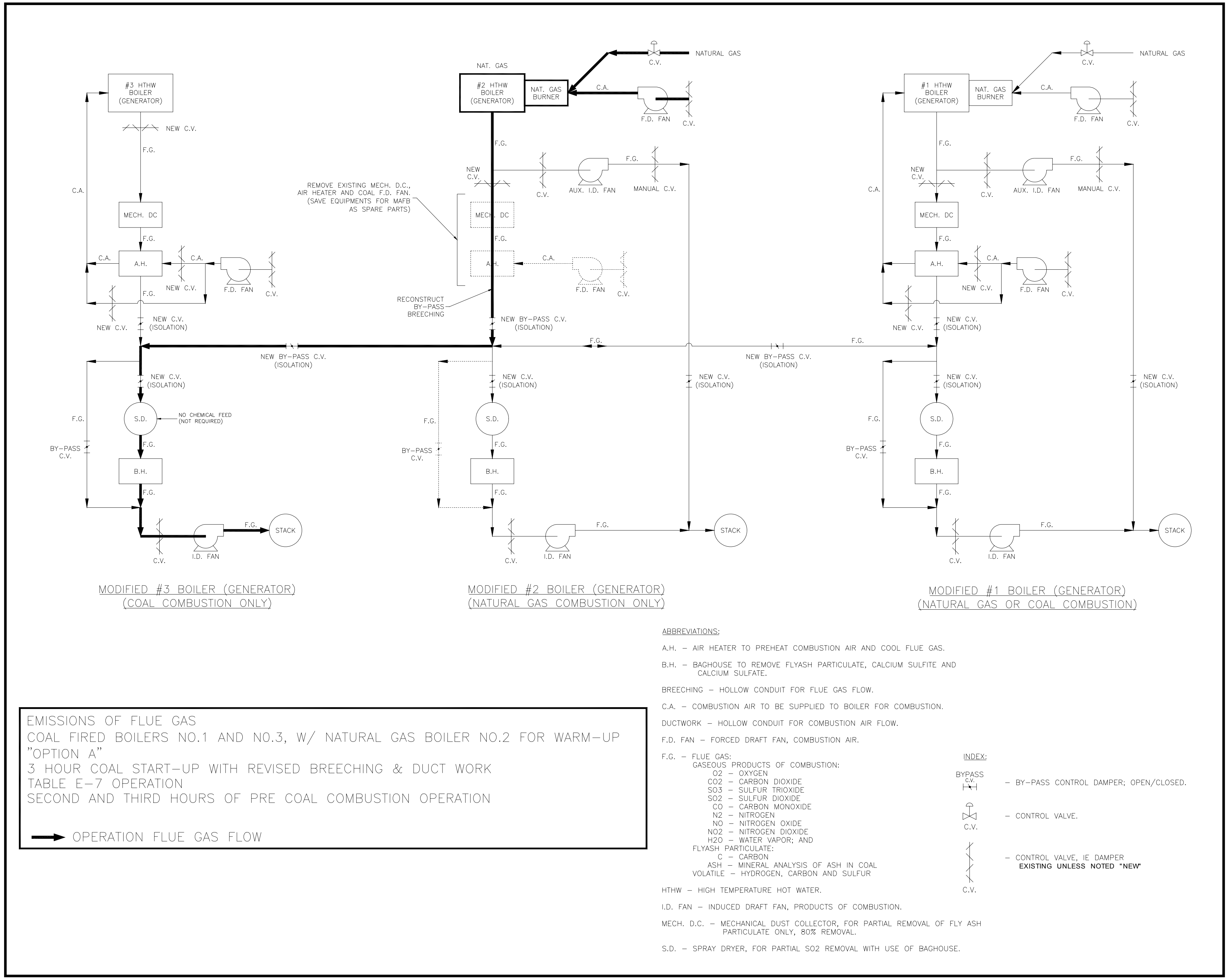


Figure D12. Flue gas flow during 2d and 3d hours of startup for Boilers No. 1 and No. 3 (No. 2 for warmup) with revised breeching and ductwork (Option "A") — 2d and 3d hours or pre-coal combustion.

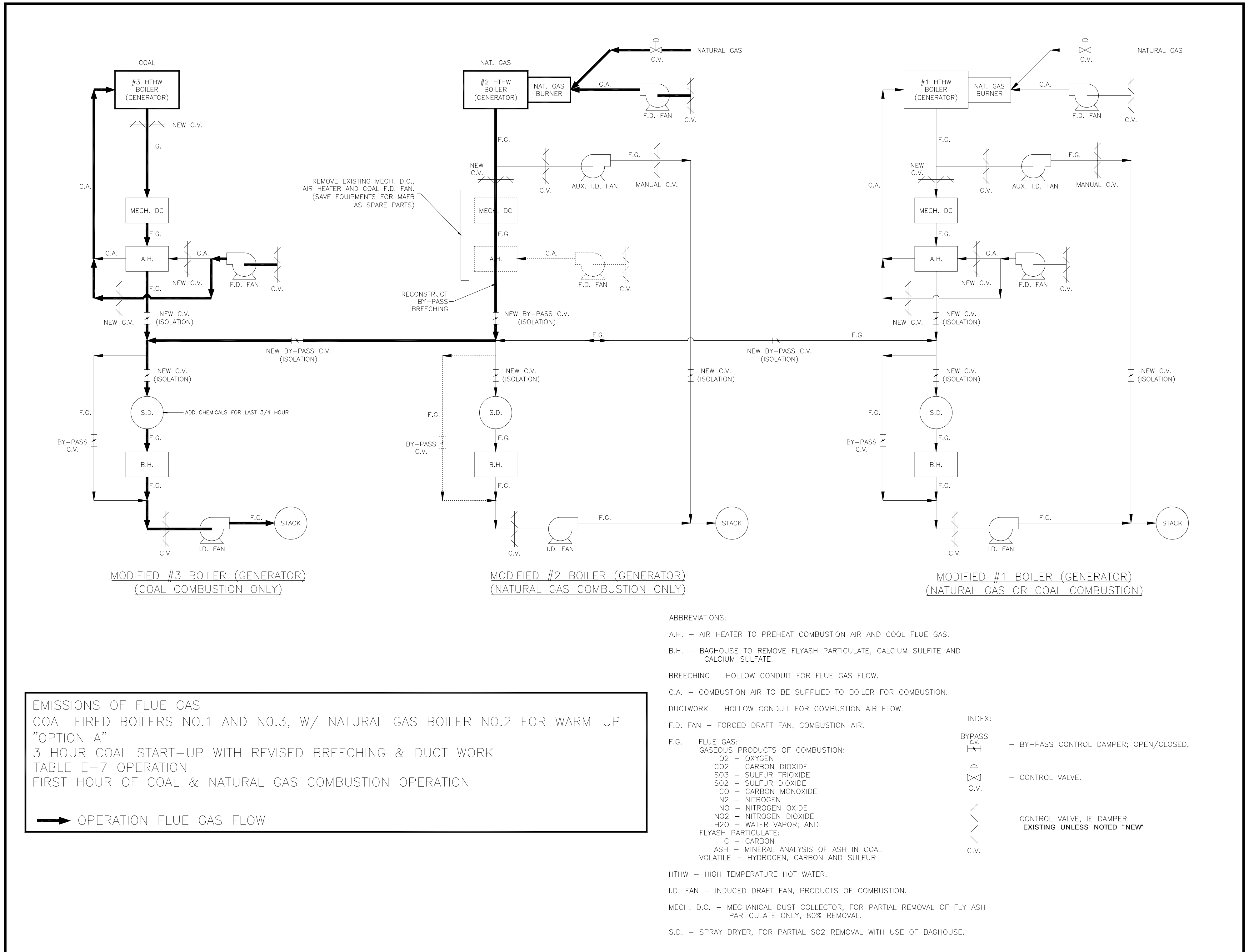


Figure D13. Flue gas flow of 1st hour of startup for Boilers No. 1 and No. 3 (No. 2 for warmup) with revised breeching and ductwork (Option "A") — 1st hour of coal and natural gas combustion.

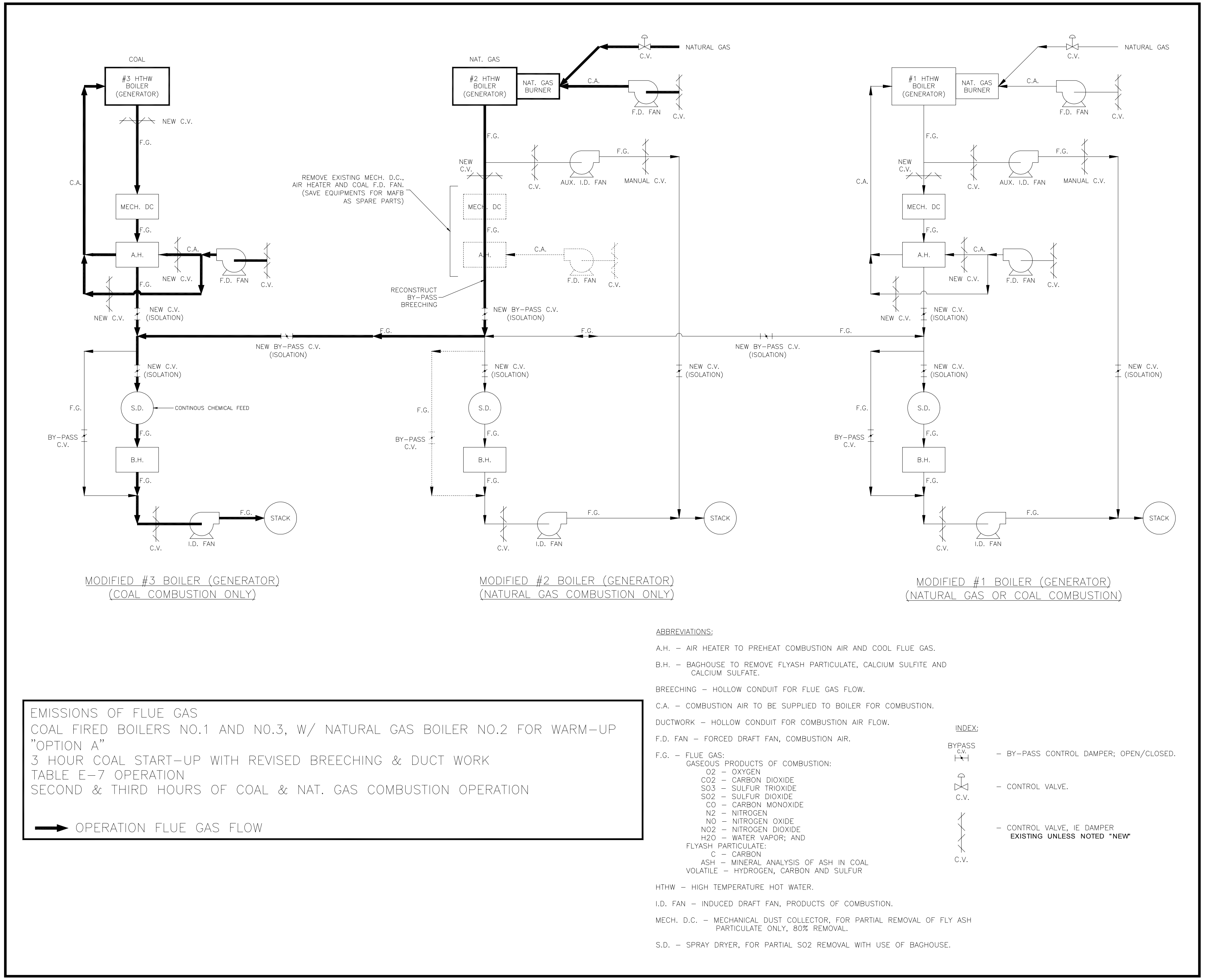


Figure D14. Flue gas flow during 2d and 3d hours of startup for Boilers No. 1 and No. 3 (No. 2 for warmup) with revised breeching and ductwork (Option "A") — 2d and 3d hours of coal and natural gas combustion.

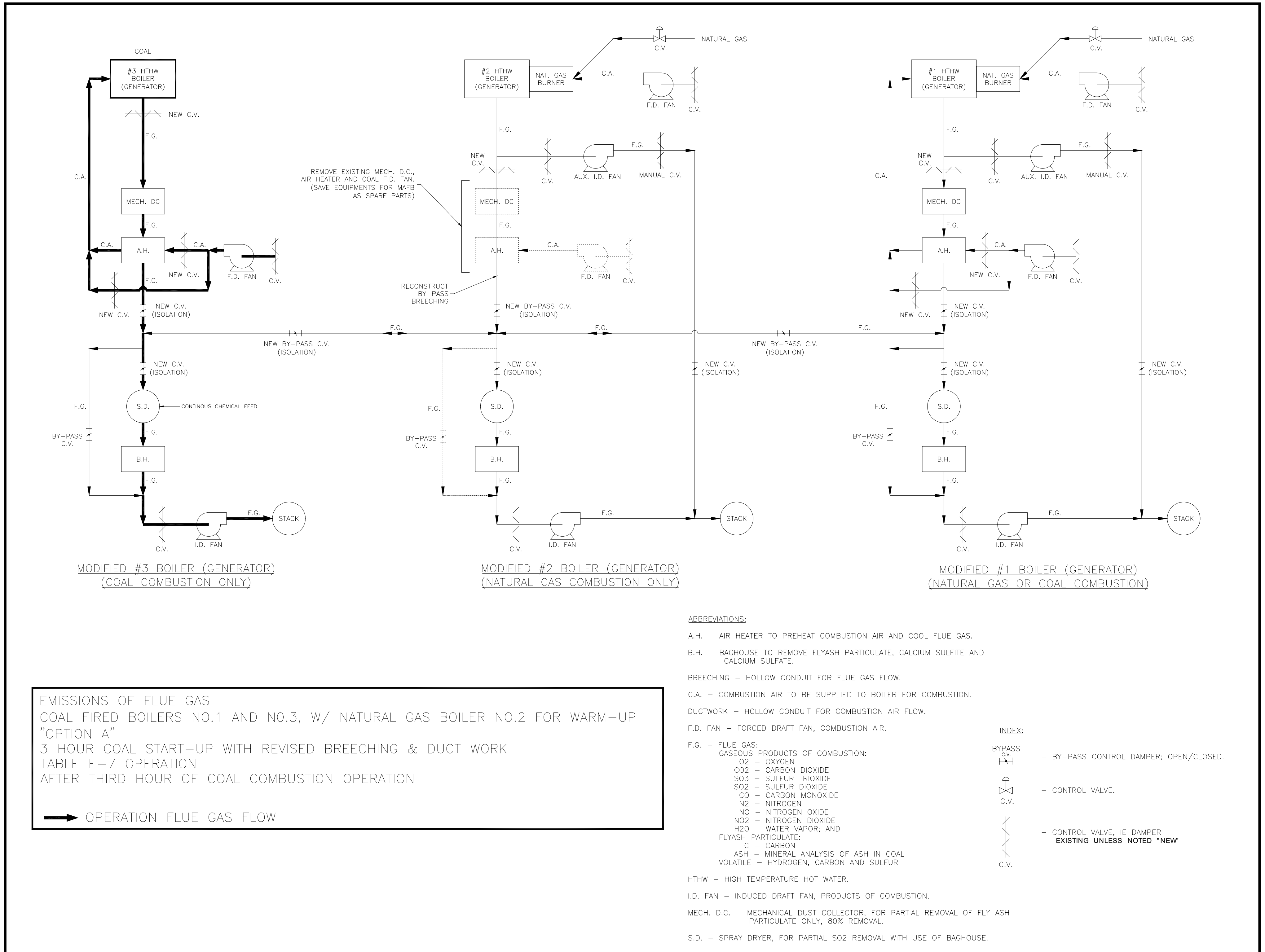


Figure D15. Flue gas flow after 3d hour of startup for Boilers No. 1 and No. 3 (No. 2 for warmup) with revised breeching and ductwork (Option "A") — after 3d hour of coal combustion.

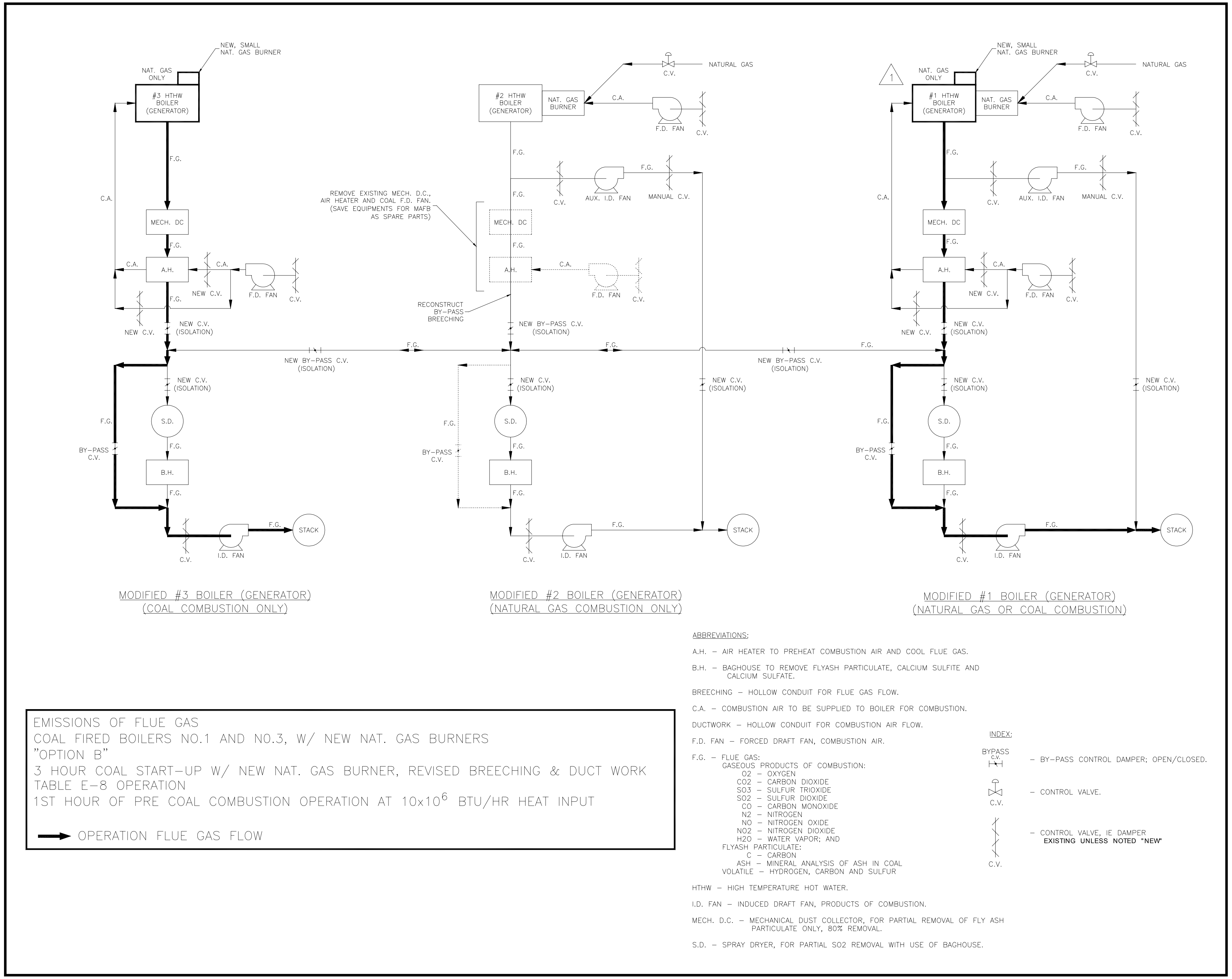


Figure D16. Flue gas flow during 1st hour of startup for Boilers No. 1 and No. 3 with new natural gas burners, revised breeching, and ductwork (Option "B") — natural gas only.

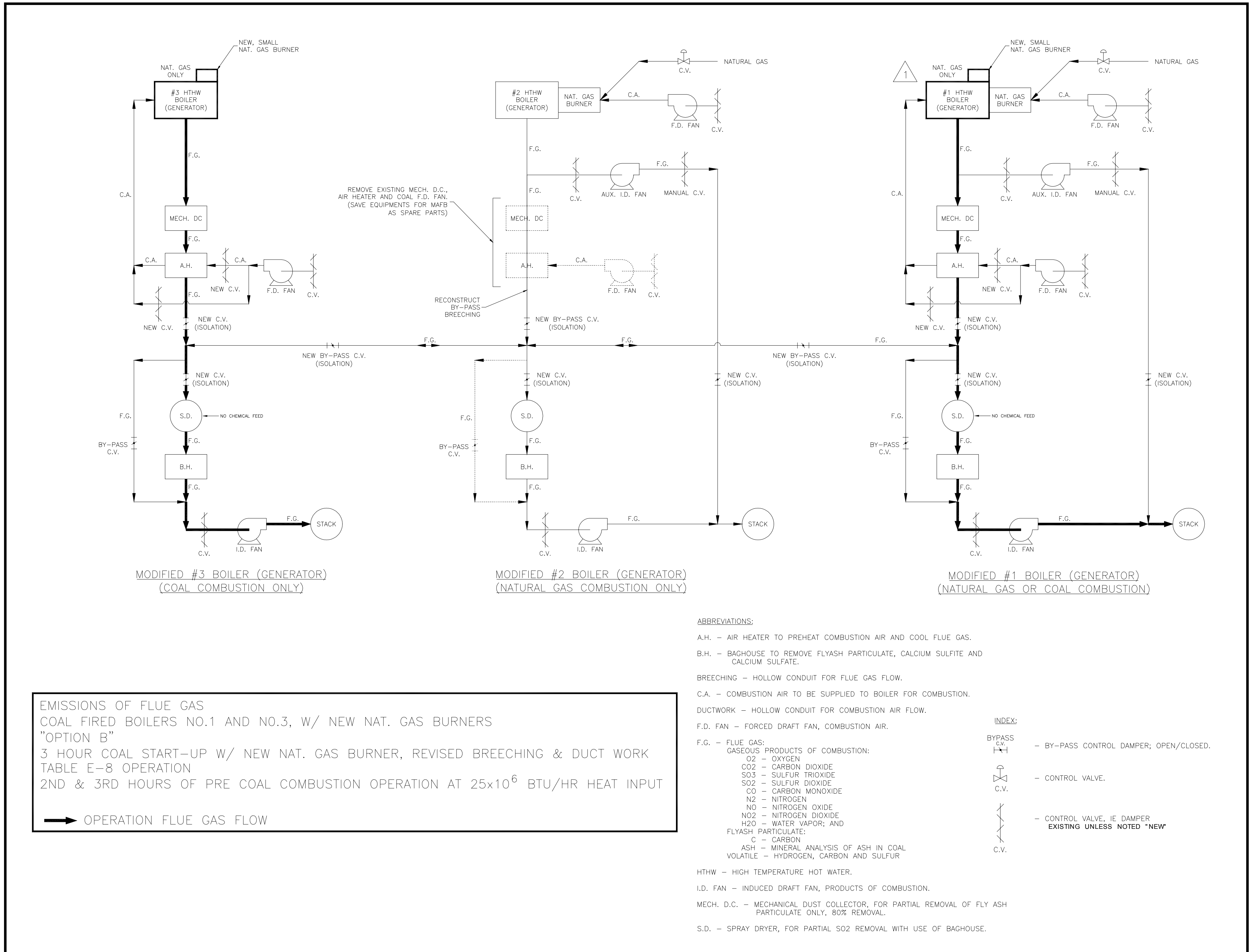


Figure D17. Flue gas flow during 2d and 3d hours of startup for Boilers No. 1 and No. 3 with new natural gas burners with revised breeching and ductwork (Option "B") — natural gas only.

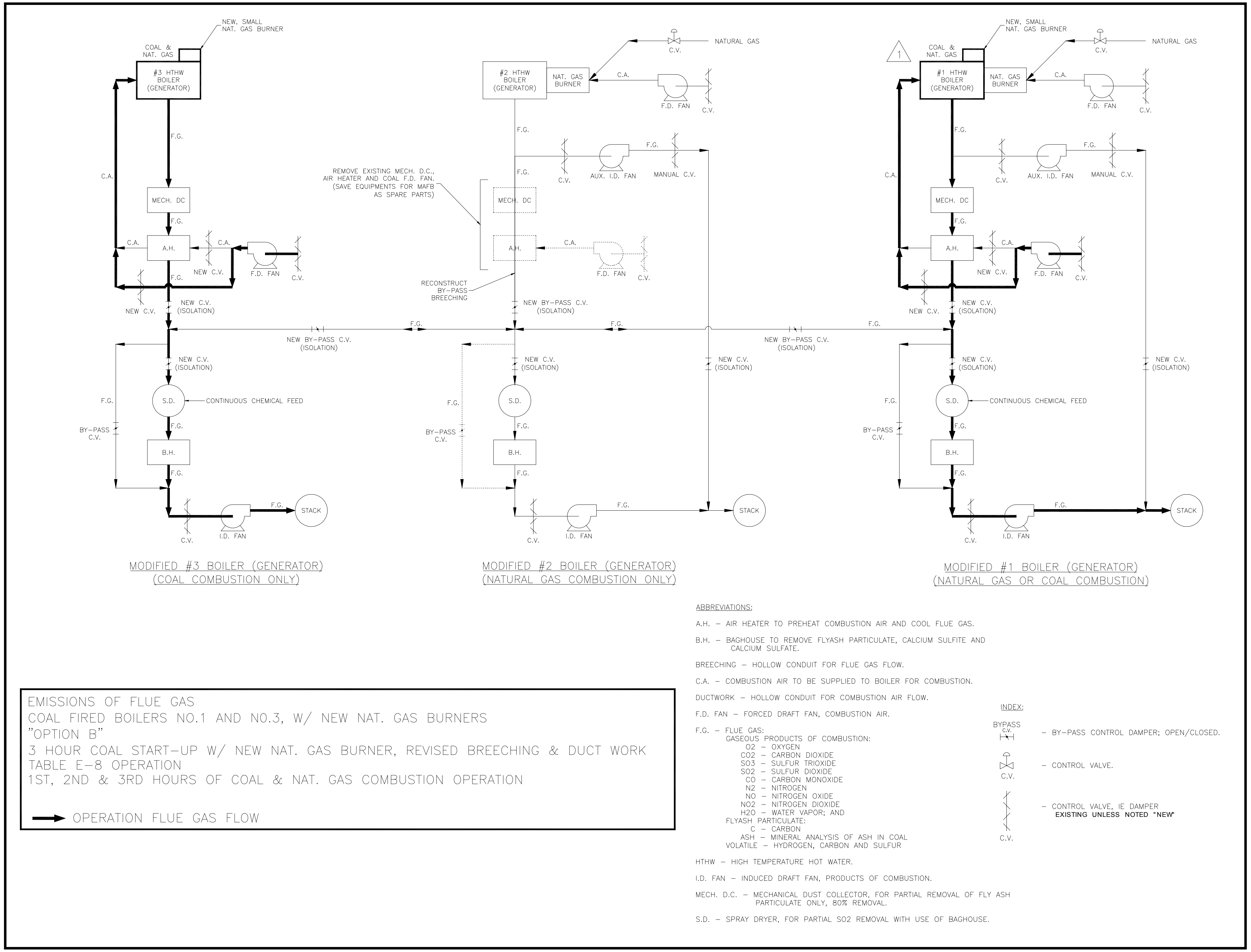


Figure D18. Flue gas flow of complete startup (1st, 2d, 3d hours) for Boilers No. 1 and No. 3 with new natural gas burners,revised breeching and ductwork (Option "B") — coal and natural gas.

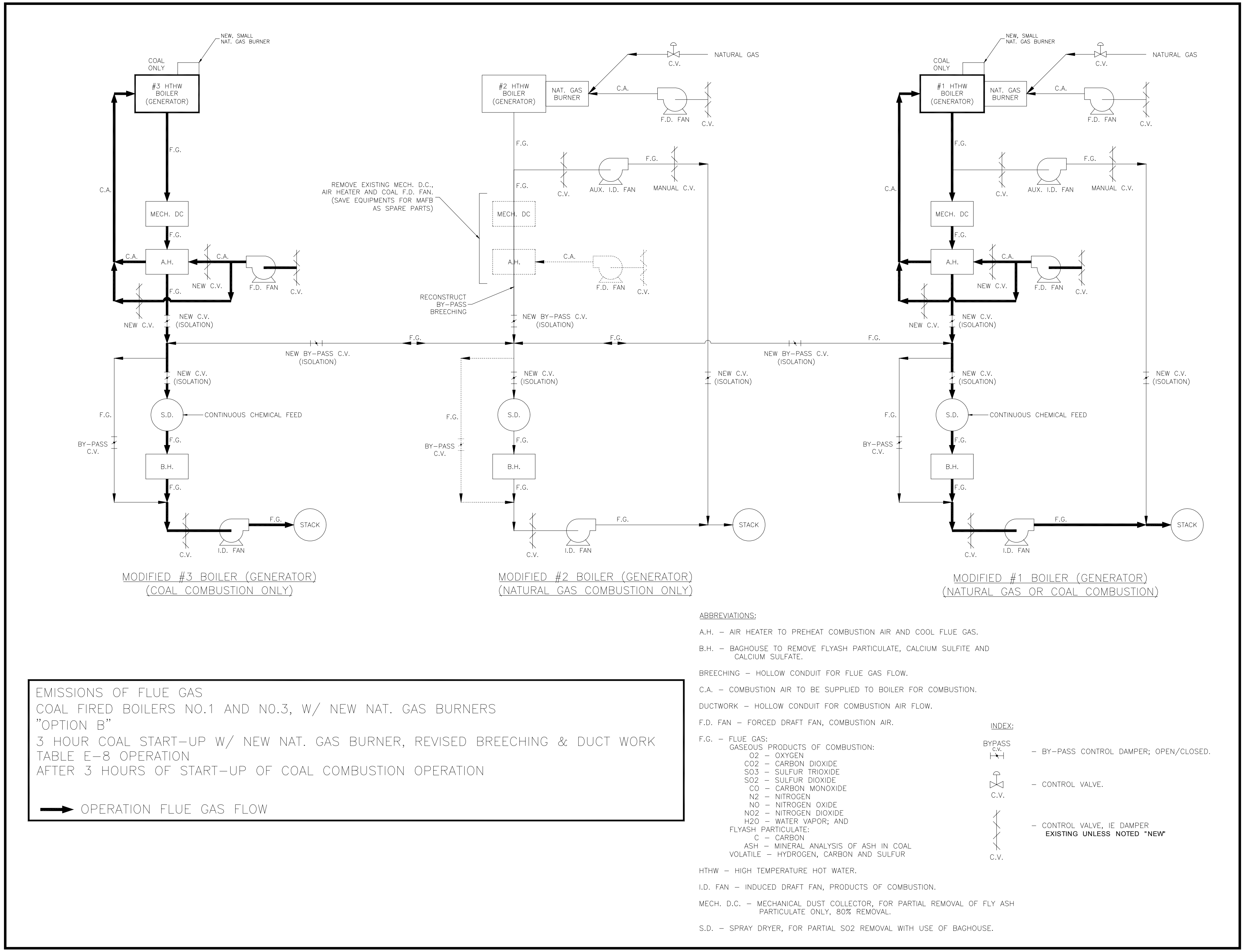


Figure D19. Flue gas flow of startup (after 3d hour) for Boilers No. 1 and No. 3 with new natural gas burners, revised breeching, and ductwork (Option "B") — coal only.

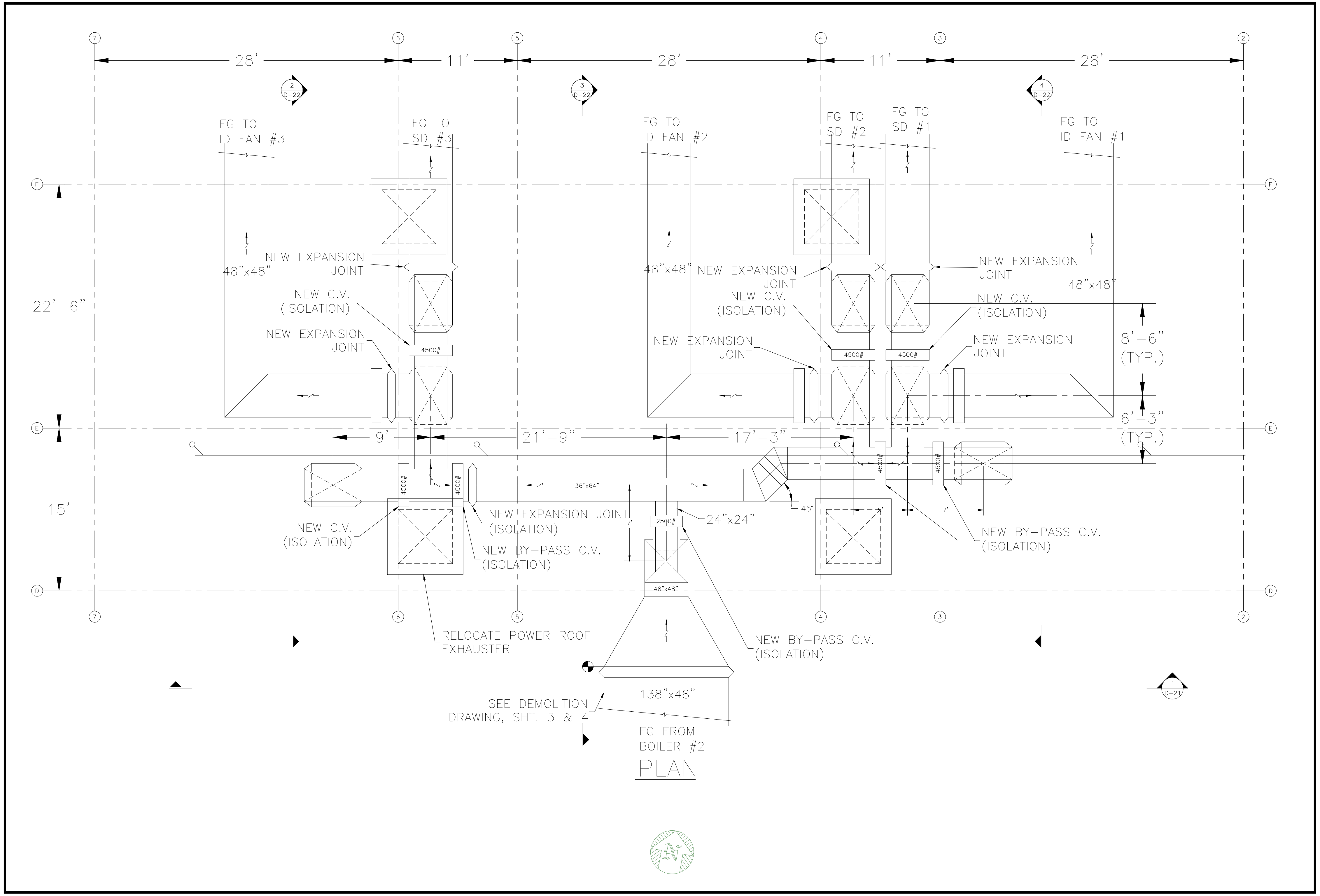


Figure D20. Conceptual drawing of breeching modifications and combustion air ductwork (Options "A" and "B").

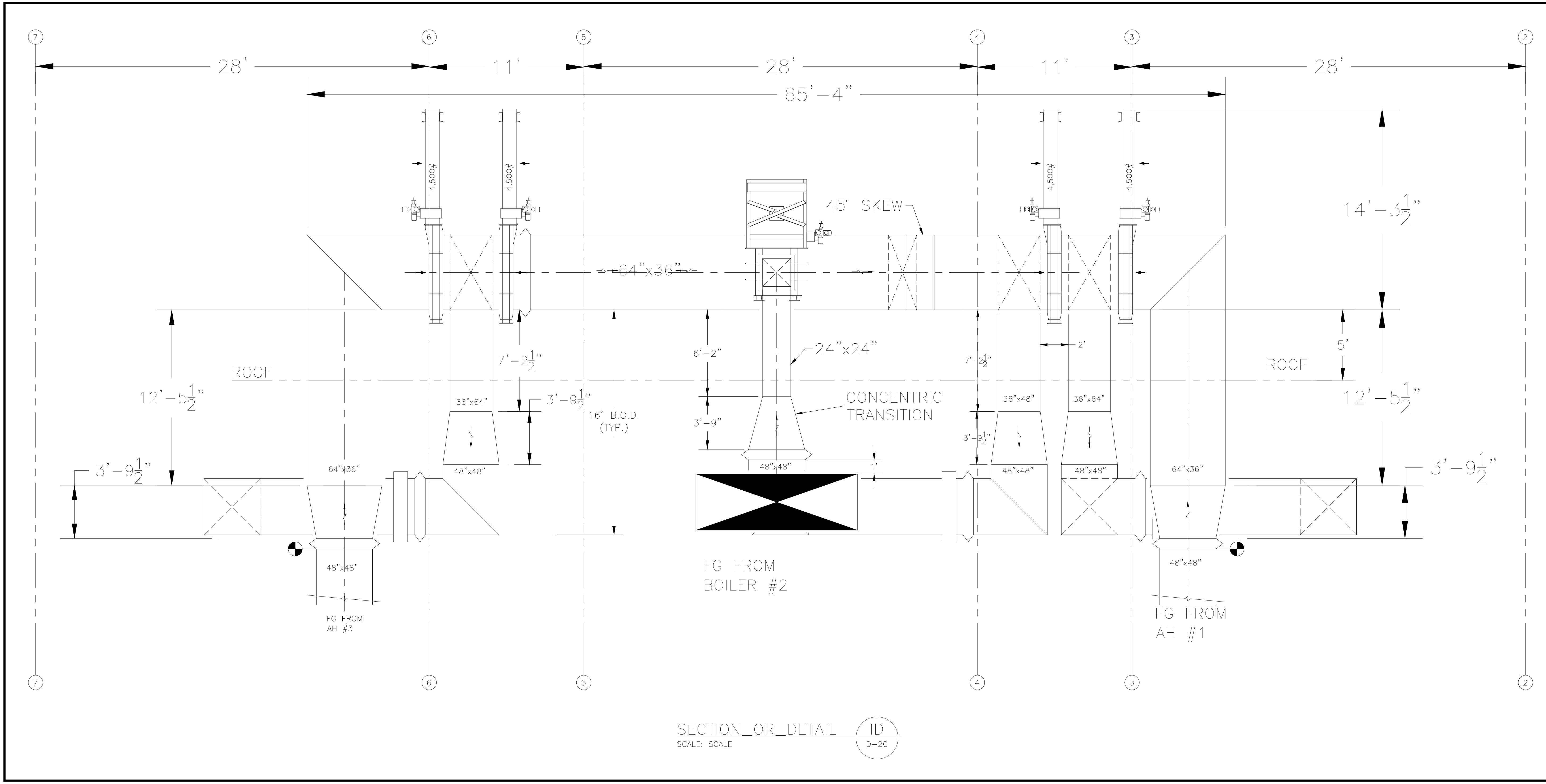


Figure D21. Detailed conceptual drawing of breeching modifications and combustion air ductwork (Options "A" and "B").

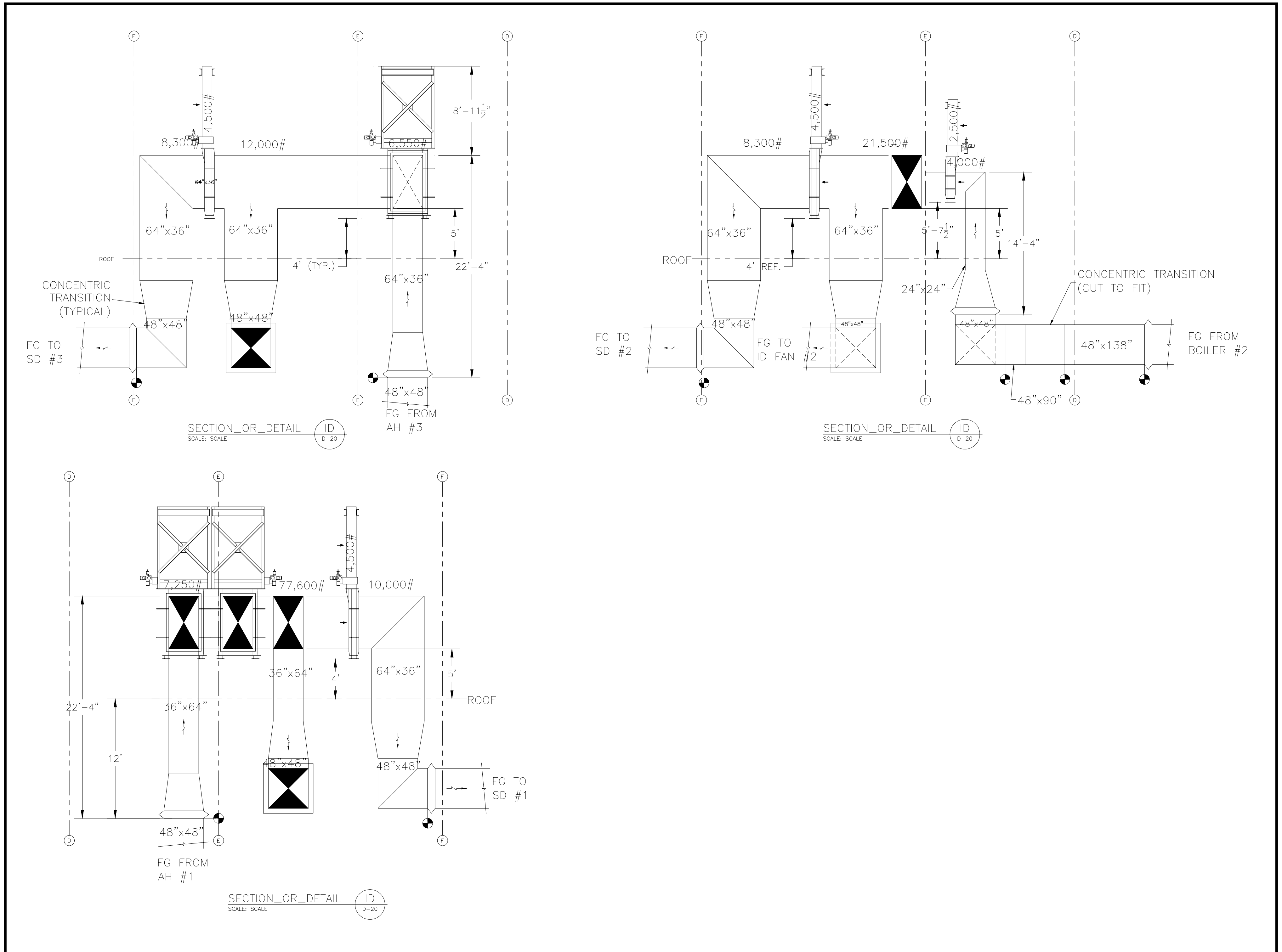


Figure D22. Detailed conceptual drawing of breeching modifications and combustion air ductwork for Options "A" and "B" (sections 2, 3, and 4).

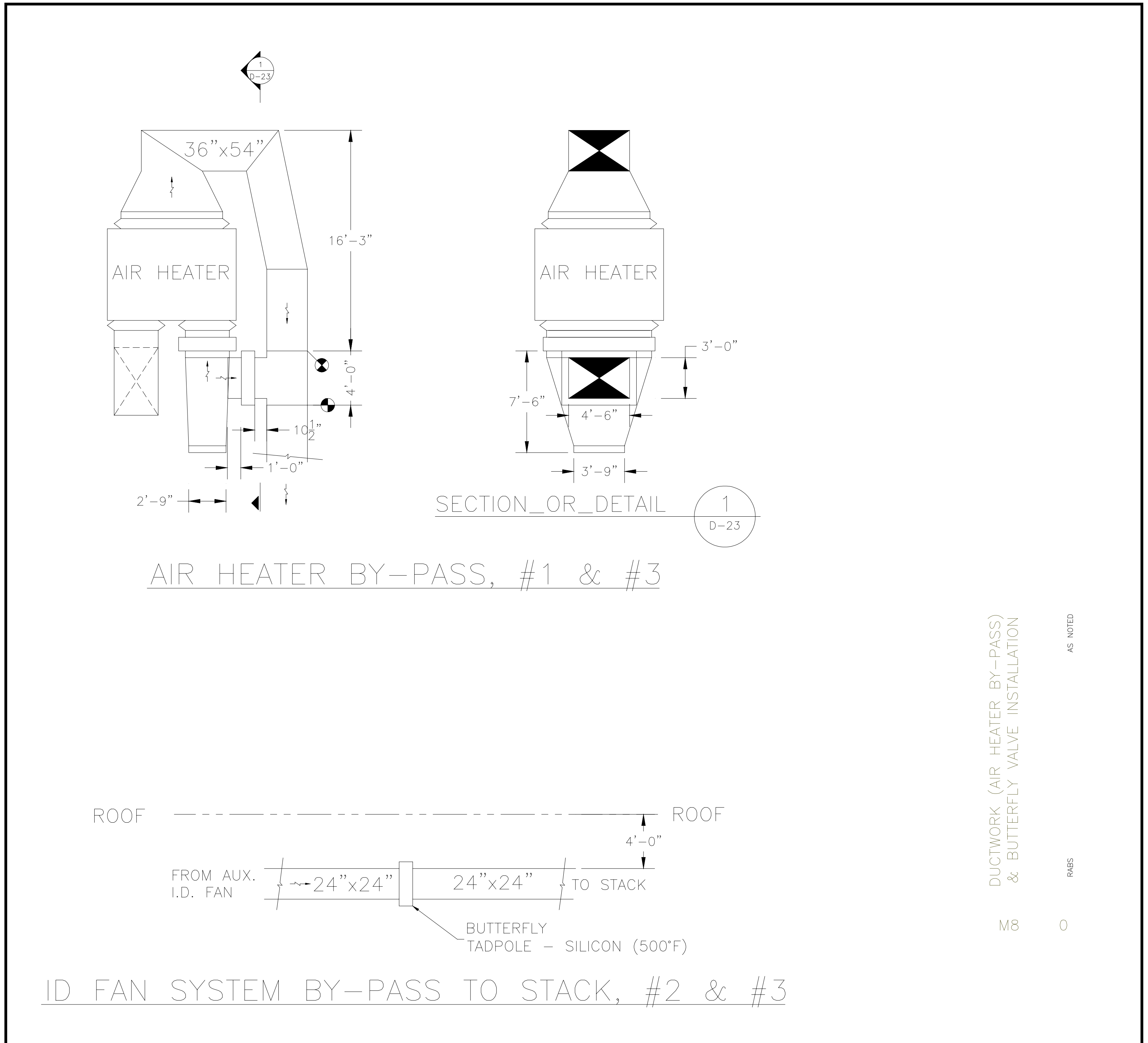


Figure D23. Detailed conceptual drawing of breeching modifications and combustion air ductwork, air heater bypass for Boilers No. 1 and No. 3., and ID fan system bypass to stacks of Boilers No. 2 and No. 3 Options "A" and "B".

Appendix E: Qualitative Emissions Test Results

Table E1. Emissions of flue gas from coal-fired Boiler No. 1 or No. 3, range of existing normal coal operation over capacity range.

General	Units	Data Acquired By	USEPA Permit Limits	Lowest (Smallest) Load	Low (Small) Load	Average Load	Moderate (Winter) Load	High (Winter) Load	Very High (Winter) Load	USEPA Predicted Publication AP-42	Comments
Heat Input	10^6 Btu/hr	(SAI) [1]	106	23.6	40.0	65.0	70.0	79.0	94.0	106	
Heat Output	10^6 Btu/hr	Calculated	85	18.9	32.1	52.1	56.1	63.3	75.4	85	
% of Boiler Maximum Heat Input	%	Calculated	100	22.3	37.7	61.3	66.0	74.5	88.7	100	
Particulate											
Uncontrolled											
Boiler Outlet	lb/10^6 Btu	(SAI) [1]	None	1.20	2.40	3.10	3.88	4.57	6.00	2.62 [2]	
Boiler Outlet	lb/hr	Calculated	4.0	28.32	96.00	201.50	271.60	361.03	564.00		Noncompliant
Partial Control											
Mechanical Dust Collector Outlet	lb/10^6 Btu	(SAI) [1]	None	0.60	0.36	0.31	0.31	0.32	0.36		
Mechanical Dust Collector Outlet	lb/hr	Calculated	4.0	14.16	14.40	20.15	21.70	25.28	33.84		Noncompliant
Total Control											
Baghouse Outlet (stack)	lb/10^6 Btu	Some Test	None	0.02	0.02	0.02	0.02	0.02	0.02	0.0048 [3]	
Baghouse Outlet (stack)	lb/hr	Calculated	4.0	0.47	0.80	1.30	1.40	1.58	1.88		Compliant
Opacity	%	(Plant) [8]	20 Max.	5	5	5	5	5	5		Fog Affects Lenses
Nitrogen Oxides (NO & NO_2)											
Uncontrolled	lb/10^6 Btu	(SAI) [1]	0.50	0.50	0.60	0.73	0.86	0.89	0.90	0.44 [4]	Noncompliant
Controlled by Operation (Stack)	lb/10^6 Btu	(SAI)/Test	0.50	0.35	0.31	0.31	0.32	0.32	0.35	0.44 [4]	Compliant
Controlled by Operation (Stack)	lb/hr	Calculated	53.0	8.26	12.40	20.15	22.40	25.28	32.90		Compliant
Controlled by Operation, O_2 Dry Volume [6]	%	Test		7.5	5.4	4.1	4.2	2.7	2.5		
Controlled by Operation, O_2 Wet Volume [7]	%	Test		7.1	5.1	3.8	3.9	2.5	2.3		
Sulfur Oxides as SO_2											
Uncontrolled											
Spray Dryer Inlet	lb/10^6 Btu	Calculated [5]	0.32	0.57	0.57	0.57	0.57	0.57	0.57		Noncompliant
Spray Dryer Inlet	lb/hr	Calculated	33.9	13.45	22.80	37.05	39.90	45.03	53.58		Noncompliant
Controlled											
Spray Dryer, on line (stack)	lb/10^6 Btu	(SAI)/Test	0.32	(0.288)	0.192	0.192	0.192	0.192	0.192		Compliant
Spray Dryer, on line (stack)	lb/hr	Calculated	33.9	6.80	7.68	12.48	13.44	15.17	18.05		Compliant

Notes:

[1] Schmidt Associates, Inc. (SAI) estimates from 200 previous stack tests.

[2] AP-42 indicates 66 lb fly ash/ton coal = (66 lb fly ash/ton)/(2000 lb/ton) (12,575 Btu/lb.) = 66 lb/25.15 x 10^6 Btu = 2.62 lb/10^6 Btu

[3] AP-42 indicates 0.12 lb fly ash/ton coal = (0.12 lb fly ash/ton)/(2000 lb/ton) (12,575 Btu/lb.) = 0.12 lb/25.15 x 10^6 Btu = 0.0048 lb/10^6 Btu

[4] AP-42 indicates 11 lb NO_X/ton coal = (11 lb NO_X/ton)/(2000 lb/ton) (12,575 Btu/lb.) = 11 lb NO_X/25.15 x 10^6 Btu = 0.44 lb/10^6 Btu

[5] lb of SO_2/10^6 Btu = (10^6 Btu/12,575 Btu/lb) (0.0036 S) (64 mol. wt. SO_2 /32 mol. wt. S) = 0.57 lb SO_2/10^6 Btu

[6] Dry O_2 is measured with a portable instrument.

[7] Wet O_2 is measured with the plant insitu analyzer.

[8] Normal opacity is 1% to 2%.

Table E2. Emissions of flue gas from natural gas-fired Boiler No. 1 or No. 2, range of existing normal natural gas operation over capacity range.

General	Units	Data Acquired By	USEPA Permit Limits	Lowest (Smallest) Load	Low (Small) Load	Average Load	Moderate (Winter) Load	High (Winter) Load	USEPA Predicted Publication AP-42	Comments
Heat Input	10^6 Btu/hr	(SAI) [1]	38	4.7	11.5	18.9	26.2	33.8	38	
Heat Output	10^6 Btu/hr	Calculated	30	3.0	9.0	15.0	21.0	27.0	30	
% of Boiler Maximum Heat Input	%	Calculated	100	12.4	30.3	49.7	68.9	88.9	100	
Particulate										
Uncontrolled										
Boiler Outlet	lb/10^6 Btu	(SAI) [1]	None	0.0021	0.0021	0.0021	0.0021	0.0021	0.0021 [2]	
Boiler Outlet	lb/hr	Calculated	4.0	0.01	0.02	0.04	0.06	0.07		Compliant
Opacity	%	(Plant) [7]	20 Max.	0	0	0	0	2		Fog Affects Lenses
Nitrogen Oxides (NO & NO_2)										
Uncontrolled	lb/10^6 Btu	(SAI)/Test	0.50	0.11	0.11	0.11	0.11	0.07	0.112 [3]	Compliant
Uncontrolled	lb/hr	Calculated	53.0	0.52	1.27	2.08	2.88	2.37		Compliant
O_2 Dry Volume [5]	%	Test		3.0	3.0	3.0	3.0	3.0		
O_2 Wet Volume [6]	%	Test		2.5	2.5	2.5	2.5	2.5		
Sulfur Oxides as SO_2										
Uncontrolled	lb/10^6 Btu	(SAI)	0.32	0.00067	0.00067	0.00067	0.00067	0.00067	0.00067 [4]	Compliant
Uncontrolled	lb/hr	Calculated	33.9	0.0031	0.0077	0.0127	0.0176	0.0226		Compliant

Notes:

[1] Schmidt Associates, Inc. (SAI) estimates from 200 previous stack tests.

[2] AP-42 indicates 1.9 lb particulate/10^6 scf natural gas = (1.9 lb particulate/10^6 scf)/(10^6 scf) (890 Btu/scf) = 1.9 lb particulate/890 x 10^6 Btu = 0.0021 lb/10^6 Btu

[3] AP-42 indicates 100 lb NO_X/10^6 scf natural gas = (100 lb NO_X/10^6 scf)/(10^6 scf) (890 Btu/scf) = 100 lb NO_X/890 x 10^6 Btu = 0.112 lb/10^6 Btu

[4] AP-42 indicates 0.6 lb SO_2/10^6 scf natural gas = (0.6 lb SO_2/10^6 scf)/(10^6 scf) (890 Btu/scf) = 0.6 lb SO_2/890 x 10^6 Btu = 0.00067 lb/10^6 Btu

[5] Dry O_2 is measured with a portable instrument.

[6] Wet O_2 is measured with the plant insitu analyzer.

[7] Normal opacity is 0% on natural gas.

Table E3. Emissions of flue gas from coal-fired Boiler No. 1 or No. 3, normal 5-hr coal start-up of existing equipment (a typical start-up cycle for most coal-fired boilers, *not* Malmstrom AFB's current operational start-up procedure).

General	Units	Data Acquired By	USEPA Permit Limits	First Hour Average	Second Hour Average	Third Hour Average	Fourth Hour Average	Fifth Hour Average	Summation Over 5 Hours	Average Over 5 Hours	Comments
Heat Input	10^6 Btu/hr [1]	(SAI)	106	8.0	14.4	21.9	26.5	30.0	100.8	20.2	
Heat Output	10^6 Btu/hr	(SAI)	85	0.0	0.0	0.0	10.0	20.0	30.0	6.0	
% of Boiler Maximum Heat Input	% [1]	Calculated	100	7.5	13.6	20.7	25.0	28.3	N/A	19.1	
Particulate											
Uncontrolled											
Boiler Outlet	lb/10^6 Btu	(SAI) [2]	None	1.67	1.89	2.10	2.31	2.58	N/A	2.23	
Boiler Outlet	lb/hr	Calculated	4.0	13.36	27.22	45.99	61.22	77.40	225.19	45.04	Noncompliant
Partial Control											
Mechanical Dust Collector Outlet	lb/10^6 Btu	(SAI) [2]	None	1.00	1.00	0.97	0.90	0.85	N/A	0.92	
Mechanical Dust Collector Outlet	lb/hr	Calculated	4.0	8.00	14.40	21.24	23.85	25.50	92.99	18.60	Noncompliant
Total Control											
Baghouse Operation				Bypass	Bypass	Bypass	On	On			
Baghouse Outlet (stack)	lb/10^6 Btu	(SAI) [2]/Test	None	1.00	1.00	.97	.02	.02	N/A	0.44	
Baghouse Outlet (stack)	lb/hr	Calculated	4.0	8.00	14.40	21.24	0.53	0.60	44.77	8.95	Non Compliant
Opacity	%	(SAI) [7]	20 Max.	80 [7]	60 [7]	50 [7]	5 [8]	5 [8]	N/A	40	Non Compliant
Nitrogen Oxides (NO & NO_2)											
Uncontrolled	lb/10^6 Btu	(SAI) [2]	0.50	1.00	0.90	0.75	0.60	0.50	N/A	N/A	Noncompliant
Controlled by Operation	lb/10^6 Btu	(SAI) [2]	0.50	1.00	0.90	0.75	0.50	0.40	N/A	0.62	Non Compliant
Controlled by Operation	lb/hr	Calculated	53.0	8.00	12.96	16.43	13.25	12.00	62.64	12.53	Compliant
Controlled by Operation, O_2 Dry [4]	%	(SAI) [2]		20.0	17.1	13.2	10.2	8.1	N/A	13.7	
Controlled by Operation, O_2 Wet [5]	%	(SAI) [2]		19.5	16.5	12.5	9.5	7.5	N/A	13.1	
Sulfur Oxides as SO_2											
Uncontrolled											
Spray Dryer Inlet	lb/10^6 Btu	Calculated [3]	0.32	0.57	0.57	0.57	0.57	0.57	N/A	0.57	Noncompliant
Spray Dryer Inlet	lb/hr	Calculated	33.9	4.56	8.21	12.48	15.11	17.10	57.46	11.49	Compliant
Controlled											
Spray Dryer Operation				Bypass	Bypass	Bypass	Partial	On			
Spray Dryer, (stack)	lb/10^6 Btu	(SAI)/Test	0.32	0.57	0.57	0.57	0.38 [6]	0.192	N/A	.41	Non Compliant
Spray Dryer, (stack)	lb/hr	Calculated	33.9	4.56	8.21	12.48	10.07	5.76	41.08	8.22	Compliant

Notes:

[1] Heat input is heat into: water, steel pressure parts (tubes & headers), refractory, insulation, casing, etc.

[2] Schmidt Associates, Inc. estimate from former start-ups.

[3] lb of $SO_2/10^6$ Btu = (10^6 Btu/12,575 Btu/lb) (0.0036 S) (64 mol. wt. SO_2 /32 mol. wt. S) = 0.57 lb $SO_2/10^6$ Btu.

[4] Dry O_2 is measured with a portable instrument.

[5] Wet O_2 is measured with the plant insitu analyzer.

[6] ½ hour with SD off (0.57 lb/$SO_2/10^6$ Btu) and ½ hour with SD on at 0.192 lb $SO_2/10^6$ Btu

[7] SAI estimate from previous start-up at other plants.

[8] Normal opacity is 1 to 2%.

Table E4. Emissions of flue gas from coal-fired Boiler No. 1 or No. 3, 3-hour coal start-up of existing equipment; circulate HTHW for 5 hr before coal light-off (Malmstrom AFB's current operational start-up procedure).

General	Units	Data Acquired By	USEPA Permit Limits	First Hour Average	Second Hour Average	Third Hour Average	Summation Over 3 Hours	Average Over 3 Hours	Comments
Heat Input	10^6 Btu/hr [1]	(SAI)	106	21.2	26.5	30.0	77.7	25.9	
Heat Output	10^6 Btu/hr	(SAI)	85	0	10.0	20.0	30.0	10.0	
% of Boiler Maximum Heat Input	% [1]	Calculated	100	20.0	25.0	28.3	N/A	24.4	
Particulate									
Uncontrolled									
Boiler Flue Gas Outlet	lb/10^6 Btu	(SAI) [2]	None	2.10	2.31	2.58	N/A	2.36	
Boiler Flue Gas Outlet	lb/hr	Calculated	4.0	44.52	61.22	77.40	183.14	61.05	Noncompliant
Partial Control									
Mechanical Dust Collector Outlet	lb/10^6 Btu	(SAI) [2]	None	0.97	0.90	0.85	N/A	0.90	
Mechanical Dust Collector Outlet	lb/hr	Calculated	4.0	20.56	23.85	25.50	69.91	23.30	Noncompliant
Total Control									
Baghouse Operation				Bypass	On	On			
Baghouse Outlet (stack)	lb/10^6 Btu	(SAI) [2]/Test	None	0.97	0.02	0.02	N/A	0.28	
Baghouse Outlet (stack)	lb/hr	Calculated	4.0	20.56	0.53	0.60	21.69	7.23	Noncompliant
Opacity	%	(SAI) [2]	20 Max.	65 [7]	5 [8]	5 [8]	N/A	25	Noncompliant
Nitrogen Oxides (NO & NO_2)									
Uncontrolled	lb/10^6 Btu	(SAI) [2]	0.50	0.75	0.60	0.50	N/A	N/A	Noncompliant
Controlled by Operation	lb/10^6 Btu	(SAI) [2]	0.50	0.75	0.50	0.40	N/A	0.53	Noncompliant
Controlled by Operation	lb/hr	Calculated	53.0	15.90	13.25	12.00	41.15	13.72	Compliant
Controlled by Operation, O_2 Dry [5]	%	(SAI) [2]		13.2	10.2	8.1	N/A	10.5	
Controlled by Operation, O_2 Wet [6]	%	(SAI) [2]		12.8	9.8	7.7	N/A	10.1	
Sulfur Oxides as SO_2									
Uncontrolled									
Spray Dryer Inlet	lb/10^6 Btu	Calculated [3]	0.32	0.57	0.57	0.57	N/A	0.57	Noncompliant
Spray Dryer Inlet	lb/hr	Calculated	33.9	12.08	15.11	17.10	44.29	14.76	Compliant
Controlled									
Spray Dryer Operation				Bypass	Partial	On			
Spray Dryer, (stack)	lb/10^6 Btu	(SAI)/Test	0.32	0.57	0.38 [4]	0.192	N/A	0.36	Noncompliant
Spray Dryer, (stack)	lb/hr	Calculated	33.9	12.08	10.07	5.76	27.91	9.30	Compliant

Notes:

[1] Heat output is heat into: water, steel pressure parts (tubes & headers), refractory, insulation, casing, etc.

[2] Schmidt Associates, Inc. estimate from former start-ups.

[3] lb of $SO_2/10^6$ Btu = (10^6 Btu/12,575 Btu/lb) (0.0036 S) (64 mol. wt. SO_2 /32 mol. wt. S) = 0.57 lb $SO_2/10^6$ Btu.

[4] ½ hour with SD off (0.57 lb $SO_2/10^6$ Btu) and ½ hour with SD on at 0.192 lb $SO_2/10^6$ Btu

[5] Dry O_2 is measured with a portable instrument.

[6] Wet O_2 is measured with the plant insitu analyzer.

[7] SAI estimate from previous start-up at other plants.

[8] Normal opacity is 1 to 2%.

Table E5. Emissions of flue gas from coal-fired Boiler No. 1 or No. 3, shut-down of coal boiler and pollution control equipment.

General	Units	Data Acquired By	USEPA Permit Limits	First Hour Average	Second Hour Average	Summation Over 2 Hours	Average Over 2 Hours	Comments
Heat Input	10^6 Btu/hr [1]	(SAI)	106	23.6	2.0	25.6	12.8	
Heat Output	10^6 Btu/hr	(SAI)	85	18.9	1.6	20.5	10.2	
% of Boiler Maximum Heat Input	% [1]	Calculated	100	22.2	1.9	N/A	12.1	
Particulate								
Uncontrolled								
Boiler Flue Gas Outlet	lb/10^6 Btu	(SAI) [2]	None	1.20	1.20	N/A	1.20	
Boiler Flue Gas Outlet	lb/hr	Calculated	4.0	28.32	2.40	30.72	15.36	Noncompliant
Partial Control								
Mechanical Dust Collector Outlet	lb/10^6 Btu	(SAI) [2]	None	0.60	0.60	N/A	0.60	
Mechanical Dust Collector Outlet	lb/hr	Calculated	4.0	14.16	1.20	15.36	7.68	Noncompliant
Total Control								
Baghouse Operation				On	On			
Baghouse Outlet (stack)	lb/10^6 Btu	(SAI) [2]	None	0.02	0.02	N/A	0.02	
Baghouse Outlet (stack)	lb/hr	Calculated	4.0	0.47	0.04	0.51	0.26	Compliant
Opacity	%	(Plant) [6]	20 Max.	5.0	0.8	N/A	2.9	Compliant
Nitrogen Oxides (NO & NO_2)								
Uncontrolled	lb/10^6 Btu	(SAI) [2]	0.50	0.50	0.50	N/A	N/A	Compliant
Controlled by Operation	lb/10^6 Btu	(SAI) [2]	0.50	0.35	0.35	N/A	0.35	Compliant
Controlled by Operation	lb/hr	Calculated	53.0	8.26	0.70	8.96	4.48	Compliant
Controlled by Operation, O_2 Dry [4]	%	(SAI) [2]		7.5	19.8	N/A	13.7	
Controlled by Operation, O_2 Wet [5]	%	(SAI) [2]		7.1	19.4	N/A	13.3	
Sulfur Oxides as SO_2								
Uncontrolled								
Spray Dryer Inlet	lb/10^6 Btu	Calculated [3]	0.32	0.57	0.57	N/A	0.57	Noncompliant
Spray Dryer Inlet	lb/hr	Calculated	33.9	13.45	1.14	14.59	7.30	Compliant
Controlled								
Spray Dryer Operation				On	On			
Spray Dryer, (stack)	lb/10^6 Btu	Test	0.32	0.29	0.05	N/A	0.27	Compliant
Spray Dryer, (stack)	lb/hr	Calculated	33.9	6.84	0.10	6.94	3.47	Compliant

Notes:

[1] Heat output is heat into: water, steel pressure parts (tubes & headers), refractory, insulation, casing, etc.

[2] Schmidt Associates, Inc. estimate from former start-ups.

[3] lb of SO_2/10^6 Btu = (10^6 Btu/12,575 Btu/lb) (0.0036 S) (64 mol. wt. SO_2 /32 mol. wt. S) = 0.57 lb SO_2/10^6 Btu.

[4] Dry O_2 is measured with a portable instrument.

[5] Wet O_2 is measured with the plant insitu analyzer.

[6] Normal opacity is 1 to 2%.

Table E6. Emissions of flue gas from coal-fired Boiler No. 1 or No. 3, coal boiler malfunction with by-pass to Boiler No. 2 spray dryer and baghouse with revised breeching and ductwork.

General	Units	Data Acquired By	USEPA Permit Limits	First Hour Average	Second Hour Average	Third Hour Average	Summation Over 3 Hours	Average Over 3 Hours	Comments
Heat Input	10^6 Btu/hr [1]	(SAI)	106	23.6	23.6	23.6	70.8	23.6	
Heat Output	10^6 Btu/hr	(SAI)	85	18.9	18.9	18.9	56.7	18.9	
% of Boiler Maximum Heat Input	% [1]	Calculated	100	22.3	22.3	22.3	N/A	22.3	
Particulate									
Uncontrolled									
Boiler Flue Gas Outlet	lb/10^6 Btu	(SAI) [2]	None	1.20	1.20	1.20	N/A	1.20	
Boiler Flue Gas Outlet	lb/hr	Calculated	4.0	28.32	28.32	28.32	84.96	28.32	Noncompliant
Partial Control									
Mechanical Dust Collector Outlet	lb/10^6 Btu	(SAI) [2]	None	0.60	0.60	0.60	N/A	0.60	
Mechanical Dust Collector Outlet	lb/hr	Calculated	4.0	14.16	14.16	14.16	42.48	14.16	Noncompliant
Total Control									
Baghouse Operation				On	On	On			
Baghouse Outlet (stack)	lb/10^6 Btu	(SAI) [2]	None	0.02	0.02	0.02	N/A	0.02	
Baghouse Outlet (stack)	lb/hr	Calculated	4.0	0.47	0.47	0.47	1.41	0.47	Compliant
Opacity	%	(Plant) [7]	20 Max.	5	5	5	N/A	5	Compliant
Nitrogen Oxides (NO & NO_2)									
Uncontrolled	lb/10^6 Btu	(SAI) [2]	0.50	0.50	0.50	0.50	N/A	N/A	Compliant
Controlled by Operation	lb/10^6 Btu	(SAI) [2]	0.50	0.35	0.35	0.35	N/A	0.35	Compliant
Controlled by Operation	lb/hr	Calculated	53.0	8.26	8.26	8.26	24.78	8.26	Compliant
Controlled by Operation, O_2 Dry [5]	%	(SAI) [2]		7.5	7.5	7.5	N/A	7.5	
Controlled by Operation, O_2 Wet [6]	%	(SAI) [2]		7.1	7.1	7.1	N/A	7.1	
Sulfur Oxides as SO_2									
Uncontrolled									
Spray Dryer Inlet	lb/10^6 Btu	Calculated [3]	0.32	0.57	0.57	0.57	N/A	0.57	Noncompliant
Spray Dryer Inlet	lb/hr	Calculated	33.9	13.45	13.45	13.45	40.35	13.45	Compliant
Controlled									
Spray Dryer Operation				On	Partial	On			
Spray Dryer, by-pass air heater	lb/10^6 Btu	(SAI)	0.32	0.18	0.28 [4]	0.18	N/A	0.21	Compliant
Spray Dryer, by-pass air heater	lb/hr	Calculated	33.9	4.25	6.61	4.25	15.11	5.04	Compliant

Notes:

[1] Heat output is heat into: water, steel pressure parts (tubes & headers), refractory, insulation, casing, etc.

[2] Schmidt Associates, Inc. estimate from former start-ups.

[3] lb of $SO_2/10^6$ Btu = (10^6 Btu/12,575 Btu/lb) (0.0036 S) (64 mol. wt. SO_2 /32 mol. wt. S) = 0.57 lb $SO_2/10^6$ Btu.

[4] 1/4 hour with SD off (0.57 lb $SO_2/10^6$ Btu) and 3/4 hour with SD on at 0.18 lb $SO_2/10^6$ Btu.

[5] Dry O_2 is measured with a portable instrument.

[6] Wet O_2 is measured with the plant insitu analyzer.

[7] Normal opacity is 1 to 2%.

Table E7. Option A: 3-hour Coal Start-up with revised breeching and ductwork; emissions of flue gas from one boiler (coal-fired Boiler No. 1 or No. 3 with natural gas Boiler No. 2 for warm-up).

General	Units	Data Acquired By	USEPA Permit Limits	Natural Gas Only Warm-up	First Hour Coal & Natural Gas Average	Second Hour Coal & Natural Gas Average	Third Hour Coal & Natural Gas Average	Summation Over 3 Hours Coal & Natural Gas	Average Over 3 Hours Coal & Natural Gas	Comments
Coal Heat Input	10^6 Btu/hr	(SAI)		0	21.2	26.5	30.0	77.7	25.9	
Natural Gas Heat Input	10^6 Btu/hr	(SAI)		38.0	38.0	38.0	38.0	114.0	38.0	
∑ Coal & Natural Gas Heat Input	10^6 Btu/hr	Calculated	106	38.0	59.2	64.5	68.0	191.7	63.9	
Heat Output, Gas Boiler	10^6 Btu/hr	(SAI)			30.0	30.0	30.0	90.0	30.0	
Heat Output, Coal Boiler	10^6 Btu/hr	(SAI)			0	10.0	20.0	30.0	10.0	
∑ Total Heat Output	10^6 Btu/hr	Calculated			30.0	40.0	50.0	120.0	40.0	
Coal Flue Gas Temperature	°F	(SAI)		0	250	350	380	N/A	N/A	
Coal Flue Gas Flow	lb/hr	(SAI)		0	43,830 [1]	40,670 [2]	38,890 [3]	N/A	N/A	
Natural Gas Flue Gas Temperature	°F	(SAI)		320	320	320	320	N/A	N/A	
Natural Gas Flue Gas Flow	lb/hr	(SAI)		35,570	35,570	35,570	35,570	N/A	N/A	
Coal & Natural Gas Flue Gas Temp.	°F	Calculated		320	281	336	351	N/A	N/A	
∑ Coal & Natural Gas Flue Gas Flow	lb/hr	Calculated		35,570	79,400	76,240	74,460	N/A	N/A	
Particulate Emissions										
Baghouse Operation				On	On	On	On			
Coal	lb/10^6 Btu	Test	None	0	0.020	0.020	0.020	N/A	N/A	
Coal	lb/hr	Calculated	4.0	0	0.424	0.530	0.600	N/A	N/A	Compliant
Natural Gas	lb/10^6 Btu	AP-42	None	0.002	0.002	0.002	0.002	N/A	N/A	
Natural Gas	lb/hr	Calculated	4.0	0.076	0.076	0.076	0.076	N/A	N/A	Compliant
Combined (Coal & Natural Gas)	lb/10^6 Btu	Calculated	None	0.002	0.008	0.009	0.010	N/A	0.009	
Combined (Coal & Natural Gas)	lb/hr	Calculated	4.0	0.076	0.500	0.606	0.676	1.782	0.594	Compliant
Opacity	%	(Plant) [5]	20 Max.	5	5	5	5	N/A	5	Compliant
Nitrogen Oxides										
Controlled by operation					No	Yes	Yes			
Coal	lb/10^6 Btu	(SAI)	0.50	Off	0.75	0.50	0.40	N/A	N/A	Noncompliant
Coal	lb/hr	Calculated	53.0	Off	15.90	13.25	12.00	N/A	N/A	Compliant
Natural Gas	lb/10^6 Btu	AP-42/Test	0.50	0.10	0.10	0.10	0.10	N/A	N/A	Compliant
Natural Gas	lb/hr	Calculated	53.0	3.80	3.80	3.80	3.80	N/A	N/A	Compliant
Combined (Coal & Natural Gas)	lb/10^6 Btu	Calculated	0.50	0.10	0.33	0.26	0.23	N/A	0.27	Compliant
Combined (Coal & Natural Gas)	lb/hr	Calculated	53.0	3.80	19.70	17.05	15.80	52.55	17.52	Compliant
Sulfur Oxides										
Spray Dryer, Chemical Feed				Off	On	On	On	N/A	N/A	
Coal	lb/10^6 Btu	Test	0.32	0	0.278	0.18	0.18	N/A	N/A	Compliant
Coal	lb/hr	Calculated	33.9	0	5.894	4.770	5.400	N/A	N/A	Compliant
Natural Gas [4]	lb/10^6 Btu	AP-42	0.32	0.001	0.001	0.001	0.001	N/A	N/A	Compliant
Natural Gas [4]	lb/hr	Calculated	33.9	0.038	0.038	0.038	0.038	N/A	N/A	Compliant
Combined Coal & Natural Gas	lb/10^6 Btu	Calculated	0.32	0.001	0.100	0.075	0.080	N/A	0.084	Compliant
Combined Coal & Natural Gas	lb/hr	Calculated	33.9	0.038	5.932	4.808	5.438	16.178	5.393	Compliant

Notes:

[1] (21.2 x 10^6 Btu/hr) (1/12,575 Btu/lb of coal) (26.0 lb wet flue gas/lb coal at 13.2% O_2 dry) = 43,830 lb/hr wet flue gas flow.

[2] (26.5 x 10^6 Btu/hr) (1/12,575 Btu/lb of coal) (19.3 lb wet flue gas/lb coal at 10.2% O_2 dry) = 40,670 lb/hr wet flue gas flow.

[3] (30.0 x 10^6 Btu/hr) (1/12,575 Btu/lb of coal) (16.3 lb wet flue gas/lb coal at 8.1% O_2 dry) = 38,890 lb/hr wet flue gas flow.

[4] Due to the small amount of natural gas SO_2 emissions, assume no reduction through spray dryer.

[5] Normal opacity is 1 to 2%.

Table E8. Options B & C: 3-hour coal start-up with new burner; emissions of flue gas from one boiler, coal-fired Boiler No. 1 or no. 3 with new natural gas burner.

General	Units	Data Acquired By	USEPA Permit Limits	Natural Gas Warm-Up(1 hr.)	Natural Gas Up To Load Warm-Up(2 hr)	First Hour Coal & Natural Gas	Second Hour Coal & Natural Gas	Third Hour Coal & Natural Gas	Summation Over 3 Hours of Coal & Natural Gas	Average Over 3 Hours	Comments
Coal Heat Input	10^6 Btu/hr	(SAI)		Off	Off	21.2	26.5	30.0	77.7	25.9	
Natural Gas Heat Input	10^6 Btu/hr	(SAI)		10.0	25.0	20.0	20.0	20.0	60.0	20.0	
∑ Coal & Natural Gas Heat Input	10^6 Btu/hr	Calculated	106	10.0	25.0	41.2	46.5	50.0	137.7	45.9	
Heat Output	10^6 Btu/hr	(SAI)		0.0	19.7	31.9	36.9	40.1	108.9	36.3	
Coal Flue Gas Temperature	°F	(SAI)		Off	Off	350	350	350	N/A	N/A	
Coal Flue Gas Flow	lb/hr	(SAI)		Off	Off	43,830 [1]	40,670 [2]	38,890 [3]	N/A	N/A	
Natural Gas Flue Gas Temperature	°F	(SAI)		250	380	350	350	350	N/A	N/A	
Natural Gas Flue Gas Flow	lb/hr	(SAI)		18,721	23,400	18,730	18,730	18,730	N/A	N/A	
∑ Coal & Natural Gas Flue Gas Temp.	°F	Calculated		250	380	350	350	350	N/A	N/A	
∑ Coal & Natural Gas Flue Gas Flow	lb/hr	Calculated		18,721	23,400	62,560	59,400	57,620	N/A	N/A	
Particulate Emissions											
Baghouse Operation				Bypass	On	On	On	On	N/A	N/A	
Coal	lb/10^6 Btu	Test	None	Off	Off	0.020	0.020	0.020	N/A	N/A	
Coal	lb/hr	Calculated	4.0	Off	Off	0.424	0.530	0.600	N/A	N/A	Compliant
Natural Gas	lb/10^6 Btu	AP-42	None	0.002	0.002	0.002	0.002	0.002	N/A	N/A	
Natural Gas	lb/hr	Calculated	4.0	0.020	0.048	0.040	0.040	0.040	N/A	N/A	Compliant
Coal & Natural Gas (Stack)	lb/10^6 Btu	Calculated	None	0.002	0.002	0.011	0.010	0.013	N/A	0.012	
Coal & Natural Gas (Stack)	lb/hr	Calculated	4.0	0.020	0.050	0.464	0.570	0.640	1.674	0.558	Compliant
Opacity	%	(Plant) [5]	20 Max.	5	5	5	5	5	N/A	5	Compliant
Nitrogen Oxide Emissions											
Controlled by operation				No	No	No	Yes	Yes			
Coal	lb/10^6 Btu	(SAI)	0.50	Off	Off	0.75	0.50	0.40	N/A	N/A	Noncompliant
Coal	lb/hr	Calculated	53.0	Off	Off	15.90	13.25	12.00	N/A	N/A	Compliant
Natural Gas	lb/10^6 Btu	Guarantee	0.50	0.07	0.07	0.07	0.07	0.07	N/A	N/A	Compliant
Natural Gas	lb/hr	Calculated	53.0	0.70	1.75	1.40	1.40	1.40	N/A	N/A	Compliant
Coal & Natural Gas (Stack)	lb/10^6 Btu	Calculated	0.50	0.07	0.07	0.42	0.32	0.27	N/A	0.33	Compliant
Coal & Natural Gas (Stack)	lb/hr	Calculated	53.0	0.70	1.75	17.30	14.65	13.40	45.35	15.12	Compliant
Sulfur Oxide Emissions											
Spray Dryer, Chemical Feed				Off	Off	On	On	On			
Coal	lb/10^6 Btu	Test	0.32	Off	Off	0.192	0.192	0.192			Compliant
Coal	lb/hr	Calculated	33.9	Off	Off	4.070	5.088	5.760			Compliant
Natural Gas [4]	lb/10^6 Btu	AP-42	0.32	0.001	0.001	0.001	0.001	0.001			Compliant
Natural Gas [4]	lb/hr	Calculated	33.9	0.010	0.025	0.020	0.020	0.020			Compliant
Coal & Natural Gas (Stack)	lb/10^6 Btu	Calculated	0.32	0.001	0.001	0.099	0.110	0.116	N/A	0.109	Compliant
Coal & Natural Gas (Stack)	lb/hr	Calculated	33.9	0.010	0.025	4.090	5.108	5.780	14.978	4.993	Compliant

Notes:
[1] (21.2 x 10^6 Btu/hr) (1/12,575 Btu/lb of coal) (26.0 lb wet flue gas/lb coal at 13.2% O_2 dry) = 43,830 lb/hr wet flue gas flow.
[2] (26.5 x 10^6 Btu/hr) (1/12,575 Btu/lb of coal) (19.3 lb wet flue gas/lb coal at 10.2% O_2 dry) = 40,670 lb/hr wet flue gas flow.
[3] (30.0 x 10^6 Btu/hr) (1/12,575 Btu/lb of coal) (16.3 lb wet flue gas/lb coal at 8.1% O_2 dry) = 38,890 lb/hr wet flue gas flow.
[4] Due to the small amount of natural gas SO_2 emissions, assume no reduction through spray dryer.
[5] Normal opacity is 1 to 2%.

Appendix F: Schmidt Associates, Inc. 1991 Letter to Ford Motor Company

chmidt associates, inc.
7333 FAIR OAKS ROAD / CLEVELAND, OHIO 44146 / PHONE (216) 439-7300
CONSULTING ENGINEERS FAX (216) 232-9939

November 27, 1991

Mr. Alex Bene'
Plant Engineering
Ford Motor Company
Cleveland Engine Plant #1
17601 Brookpark Road
Cleveland, Ohio 44142

Reference: Existing Coal-Fired Spreader Stoker And Chain Grate Boilers Start-Up Sequence At Ford Motor Company Cleveland Complex

Dear Mr. Bene':

My professional opinion has been requested concerning how rapidly the above referenced boilers can be started up.

These boilers operate at a 150 psig saturated steam condition. There are several issues which must be addressed on the start-up of these boilers so that they will not be destroyed mechanically or any unsafe condition(s) possibly exist during start-up.

1. A safe condition of start-up will allow sufficient time for the metal thickness in the drums (steam and mud) to heat up from the fire side to the water side. The possibility of creating excessive strains due to unequal heating of the drum thickness increases as start-up time is decreased. The mud drum is full of water and cools the inside of the drum metal at the same time the flue gas is heating up the outside of the drum metal. This time rate of metal heating must be limited or pressure part(s) failure will occur. The required time to meet this condition is approximately six (6) hours from a "cold" start-up or five (5) hours from a "hot" start-up (steam drum at 5 psig). When a cold boiler is hydrostatically pressure tested and tubes drip water where they meet the drums or headers, this is an indication (from past experiences) of too rapid a start-up.

   Rapid start-up of boilers is an unsafe condition with respect to the ASME fired pressure parts. Rapid start-up of boilers can result in ruptured furnace tubes, eventual steam and mud drum failure, and can also be dangerous to operating personnel.

2. The furnace construction of the above boilers consists of carbon steel furnace tubes full of water which are exposed to the radiant heat of the flame. Directly behind these steel tubes is refractory material which also sees the radiant heat of the flame. After any boiler has been off-line for any extended period of time (5 days), the ambient air cools the carbon steel tubes to 80°F temperature. At initial start-up of

SCHMIDT ASSOCIATES, INC.

Mr. Alex Bene'
Ford Motor Company
Cleveland Engine Plant #1
Page 2

the boiler, when fire is first lighted in the furnace, the carbon steel tubes are 80°F and increased in temperature to approximately 600°F without any steam production. The carbon steel should not be increased in temperature at a more rapid rate than 75°F per hour. The time to meet this requirement is:

600°F -80°F Divided by 75°F = 6.93 Hours
Or, Approximately Seven (7) Hours

This must be a slow, uniform temperature increase. The refractory material behind the tubes will reach 1800° operating temperature which is increasing the refractory material at a rate of 246°F per hour. If the time is decreased from the above, there will be damage to the carbon steel tubes and refractory. The total life of these boilers will be reduced to approximately 25 to 30 years by forcing them on the line at the above rapid rate.

3. The same applies as in item 1 above except that the time requirement for the tubes is:

600°F -80°F Divided by 50°F/Hr. = 10.4 Hours
Or, Approximately 10 Hours

For the Refractory:

1800°F -80°F Divided by 10.4 Hours = 165°/Hr Increase

The life of these boilers would be extended 40 to 50 years under this start-up scenario of 50°F increase per hour of tube material.

4. After the above partial start-up time, the flue gas temperature must be increased at the economizer or air heater outlet to approximately 400°F by bypassing the flue gas around the baghouse or power "off to the electrostatic precipitator (ESP)", and the steam flow from the boiler increased to approximately 35%, which will take approximately one (1) hour. Now the flue gases can enter the "cold" baghouse or the power started to the ESP, rapidly heating up the bags and carbon steel baghouse or ESP, and rapidly passing through the dew point temperature so as not to "blind" the bags or damage the ESP.

5. Historically boilers are not damaged during the normal day-to-day operation of the equipment. The life of a boiler is a direct relationship to the following:

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a. Water Treatment Quality, which is irrelevent to this discussion.
b. Excess Airs and Velocity of Flue Gases Flowing Around The Tubes, which cause wear, and also irrelevent to this discussion.
c. Method of Starting Up a Boiler, which is extremely relevant to the above discussion.

From the time coal is first ignited in a boiler until the baghouse or ESP can be placed into operation is the following:

	25 - 30 Years Life	40 - 50 Years Life
Warm Up Carbon Steel Tubes	6.93 Hrs.	10.4 Hrs.
Increase Flue Gas Temp. to 400°F	1.0 Hr.	1.0 Hr.
Flue Gas may now enter the Baghouse or ESP	7.93 Hrs.	11.4 Hrs.

The remaining life of your existing boilers is twenty (20) to twenty-five (25) years for the 1950 units and forty (40) years or more for the 1970 unit. The reason these boilers have remaining life is because of the excellent care they have received, including during start-up. If the start-up time is reduced from the current 11.4 hours to 4 - 5 hours, the life of these existing boilers will be reduced to less than half of their remaining life. This would be a very unwise engineering decision as well as an unsafe one.

The boiler installed at the Ford Motor Company Cleveland Complex will exceed 20% stack opacity during the low temperature start-up. In view of the above explanation, the Ohio EPA limitation of three (3) hours of opacity greater than 20% is unreasonable, unsafe, and unatainable without damage to the boilers. If the 3-hour start-up is forced on the plant, then furnace tube failures should be expected, the metallurgical grain structure of the steel drums will change and potential personnel injury anticipated.

All of the information contained herein is my professional engineering opinion from experience of working with boilers for the last forty (40) years.

Very truly yours,

SCHMIDT ASSOCIATES, INC.

Charles M. Schmidt

Charles M. Schmidt, P.E.
ps

Blind to R. Futryk

Appendix G: Detailed Construction Cost Estimates

Opacity Monitor Modifications for All Options

New analyzer for boiler No. 2			$30,200
New analyzer installation			$10,000
Blower Kit (heater)			
2/stack x 2 stacks x $2,290			$5,800
Blower kit (heater) Installation			$2,000
Purge Air Piping (typical for three analyzers)			
Filter Mods	$800		
75ft of 3-in. Sched 40 @ $30/ft.	$2,250		
Roof Penetration w/curb	$500		
Misc. Fittings, etc.	$250		
3 @ a total of	$3,800	=	$11,400
Extend Nipple			
3 @ $750 each			$2,250
Analyzer enclosure heating			
6 @ $750 each			$4,500
Calibration & Checkout			$10,000
Sub-Total			$76,150
Mobilization			$3,810
Sub-Total			$79,960
Overhead & Supervision (15 percent)			$12,000
Sub-Total			$91,960
Profit (5 percent)			$4,600
Contingency (10 percent)			$9,240
Total Opacity Monitor Modifications			**$105,800**

Combustion Air Revision for All Options

1. Air Heater Combustion Air Bypass for Flue Gas Temperature Control - Cost per Generator:

A. FD Fan Discharge *Variable Static Pressure versus Heat Input*

	Material	Labor	Subtotal
Pressure Transmitter	$2,500	$750	
Input Card to CPU	$6,100	$750	
Output Card	$6,100	$750	
Service Engineer (3 days)		$3,000	
	$14,700	$5,250	$19,950

B. Flue Gas Air Heater Discharge Constant Temperature

	Material	Labor	Subtotal
Damper No. 1	$10,600	$4,000	
Ductwork	$1,000	$1,200	
Damper No. 2	$5,400	$4,000	
Ductwork 3 x 3 x 20-ft	$3,000	$3,200	
Output Card	$6,100		
I/P Converter (2)	$600	$200	
Service Engineer (3 days)		$3,000	
Damper No. 3	$6,500	$4,000	
Ductwork		$1,000	
Flow Indicator	$5,000		
I/P Converter (1)	$300	$100	
Service Engineer (3 days)		$3,000	
	$38,500	$23,700	$62,200
C. Service Engineer Travel Expenses			$3,750

2. Air Heater Seals to Stop Air Infiltration to Flue Gas Side

	Material	Labor	Subtotal
New Seals	$9,500	$14,000	
New Baskets	$52,000	$28,000	
	$61,500	$42,000	$103,500

3. Combustion Air Ductwork

	Material	Labor	Subtotal
Material 253 sq ft x 10.0 lb/ sq ft x $1.30/lb =	$3,290		
Labor 253 sq ft x 10.0 lb/ sq ft x $1.30/lb =		$3,290	
Sub-Total for 1, 2 and 3 for one generator			$195,980
Sub-Total for two generators			$391,960
Mobilization			$19,600
Sub-Total			$411,560
Overhead & Supervision (15 percent)			$61,740
Sub-Total			$473,300
Profit (5 percent)			$23,670
Contingency (10 percent)			$47,330
Total Combustion Air Revision			**$544,300**

Demolition for Options "A" & "B"

Boiler No. 3 - Flue Gas	
Seal off area & wet down	$5,000
712 sq ft at $3.50/ sq ft (insulation)	$2,500
712 sq ft at $5.10/ sq ft (1/4-in.plate + 25 stif (steel)	$3,631
	$11,130
Boiler No. 2 - Flue Gas	
Seal off area & wet down	$40,000
2,987 sq ft at $3.50/ sq ft (insulation)	$10,600
2,987 sq ft at $5.10/ sq ft (steel)	$15,240
	$65,840
Boiler No. 1 - Flue Gas	
Seal off area & wet down	$5,000
528 sq ft at $3.50/ sq ft (insulation)	$1,850
528 sq ft at $5.10/ sq ft (1/4-in. plate + 25%) steel	$2,700
	$9,550
Boiler No. 2 - Combustion Air	
Seal off area in No. 2 boiler flue gas above	
1,266 sq ft at $3.50/ sq ft (insulation)	$4,500
1,266 sq ft at $5.10/ sq ft (steel)	$6,500
	$11,000
Steel is breeching, stiffeners & hangers.	
Sub-Total No. 1	$97,520
Mobilization	$4,880
Sub-Total No. 2	$102,400
Overhead & Supvr. (15%)	$15,400
Sub-Total No. 3	$117,800
Profit (5%) (sub-total No. 3)	$5,900
Contingency (10% of sub-total No. 3)	$11,800
Total Demolition	**$135,500**

Structural Roof for Options "A" and "B"

		Qty	Sq ft	lb/ft	lb	$/lb ($/ea)	$ Cost
1. Roof Area Breeching							
A	*Steel Posts – 6-in. Sch 80*	19	6	28.57	3,257	$1.30	$4,240
	1/2-in. Plate Top & Bottom	38	1	20.4	775	$1.50	$1,170
B	*14-in. Beams (14-in. x 8-in.)*	5	28	53	7,420	$1.30	$9,650
		2	12	53	1,272	$1.30	$1,660
		2	18	53	1,908	$1.30	$2,480
		1	25	53	1,325	$1.30	$1,730
		1	30	53	1,590	$1.30	$2,070
		1	16	53	848	$1.30	$1,110
C	*10-in. Beams (10-in. x 8-in.)*	3	18	45	2,430	$1.30	$3,160
		8	15	45	5,400	$1.30	$7,020
D	*8-in. Beams (8-in. x 6-½-in.)*	8	12	28	2,688	$1.30	$3,500
		4	6	28	672	$1.30	$880
E	*Subtotal*				29,585		$38,670
F	*Contingency @ 20%*						$7,740
G	*Bracing @ 20% of Material & Contingency*						$9,290
H	*Labor @ 100% of Material & Contingency*						$46,410
I	*Pitch Pockets (Labor & Material)*	19				$500.00	$9,500
J	*Connection to existing steel*	19				$300.00	$5,700
K	*Access Platforms (Damper motors)*	8				$3,000.00	$24,000
L	*Finish Paint (Labor & Material)*						$3,000
M	*Crane (120 ft Jib), Billings, MT.*						
	**Travel (3-days)*	3				$3,550.00	$10,650
	**Set-up (1-day)*	1				$3,550.00	$3,550
	**Remove (1-day)*	1				$3,550.00	$3,550
	Usage (2-days)	2				$3,550.00	$7,100
N	*Sub-Total*						$169,160
O	*Mobilization*						$8,460
P	*Sub-Total*						$177,620
Q	*Overhead & Supervision (15%)*						$26,650
R	*Sub-Total*						$204,270
S	*Profit (5%)*						$10,220
T	*Contingency (10%)*						$20,410
U	*Installed Steel Total Estimate*						$234,900

* This same crane will be used for breeching and only the usage days will appear on breeching cost.

New Flue Gas Breeching for Options "A" and "B"

Control Dampers, Isolation Dampers & Expansion Joints

Breeching	
Breeching area: 5,282 sq ft ¼-in.	
Material 5,282 sq ft x (10.2 lb/sq ft + 25%)	
67,345 lb x $1.30 =	$87,550
Labor, normal	
67,345 lb x $1.50 =	$101,020
Premium labor (inside plant at roof area)	
(2,420 sq ft inside) (12.75 lb/ sq ft) ($1.50) =	$46,250
Insulation	
5,282 sq ft x $15.00/ sq ft (labor & material)	
60% labor	$47,540
40% material	$31,700
Premium Labor (2,420 sq ft x $5.00/sq ft)	
(inside plant at roof area)	$12,100
Weathertight lagging	
5,282 sq ft x $3.00/ft	
70% labor	$11,100
30% maintenance	$4,800
Breeching tie-ins - welder 28 ft/day one pass (3 pass = 9.33 ft/day)	
Boiler No. 1 48 x 48 4 x 4 ft = 16 ft x 3 x 2 x $46.90	$4,500
Boiler No. 2 48 x 48	$4,500
Boiler No. 3 48 x 48	$4,500
Insulation Repair	
Boiler No. 1 16 ft + 16 ft = 32 ft ($70/ft.)	$2,240
Boiler No. 2 16 ft + 16 ft = 32 ft ($70/ft.)	$2,240
Boiler No. 3 16 ft + 16 ft = 32 ft ($70/ft.)	$2,240

New Flue Gas Breeching (cont'd.)

	Material	Labor
Boiler No. 3		
- Damper 12 ft x 5 ft (CV3-1) Control Damper (I/P operation)	$14,800	
12 ft + 12 ft + 5 ft + 5 ft = 34 ft x $140/ft x (2 ends)		$9,500
- Expansion Joint for CV3-1	$4,200	
12 ft + 12 ft + 5 ft + 5 ft = 34 ft x $140/ft x (2 ends)		$9,500
Boiler No. 1		
- Control Damper 12 ft x 5 ft for CV1-1 Pneumatic with I/P	$14,800	$9,500
- Expansion Joint	$4,200	$9,500
Boiler No. 3 Isolation Damper & Expansion Joint		
3 Isolation Dampers 4 ft x 4 ft ($18,200 each)	$54,600	
Labor 4 ft x 4 ft = 16 ft x 3 dampers x $140/ft (2 ends)		$13,440
Rigging (labor)		$13,440
4 Expansion Joints 4 x $2,100/each	$8,400	
4 ft x 4 ft side = 16 ft x (4 expansion joints) x $140/ft (2 ends)		$17,920
Boiler No. 1 Isolation Damper		
3 Isolation Dampers	$54,600	
Labor		$13,440
Rigging		$13,440
Expansion Joint	$8,400	$17,920
Boiler No. 2		
CV - 24-in. x 24-in. (2 x 2 ft)	$4,000	
2 ft x 4 ft = 8 ft x $140/ft (2 ends)		$2,240
Expansion Joint	$1,600	
2 ft x 4 ft = 8 ft x $140/ft (2 ends)		$2,240
Isolation Damper		
1 damper = 4 ft x 4 ft (see boiler no. 3) including rigging	$18,200	$8,960
Expansion Joint (see boiler no. 3)	$2,100	$4,480
2 dampers = 2 ft x 2 ft @ $6,800/each	$13,600	
2 ft x 4 ft x $140/ft (2 ends)		$4,480
Rigging		$4,480
Subtotal	$720,260	
Mobilization	$36,020	
Subtotal	$756,280	
Overhead & Supervision (15%)	$113,450	
Subtotal	$869,730	
Profit (5%)	$43,490	
Contingency	$86,980	
Total Breeching	**$1,000,200**	

One (1) New Sidewall Burner For Boiler No. 1 And Boiler No. 3 (Option "B")

	Material	Labor
One (1) 25 MMBtu/hr Heat Input Burner	$80,000	$10,000
Startup services		$10,000
Tube bending	$17,000	$17,000
Gas piping	$2,400	$3,100
HTHW flow switches	$3,000	$2,500
Additional safety valve	$20,000	$10,000
Hand control (manual)	$2,500	$2,500
Automatic I/P	$600	$200
Power and control wiring	$3,000	$7,100
Subtotals	$128,500	$62,400
Total material and labor (1 boiler)	$190,900	
Total material and labor (2 boilers)	$381,800	
Mobilization	$19,090	
Subtotal	$400,890	
Overhead supervision (15%)	$60,140	
Subtotal	$461,030	
Profit (5%)	$23,060	
Contingency (10%)	$46,110	
Total for burners	**$530,200**	

Two (2) New Sidewall Burners for Boiler No. 1 And Boiler No. 3 (Option "C")

	Material	**Labor**
Two (2) 25 MMBtu/hr Heat Input Burners	$120,000	$20,000
Startup Services (Burner)		$10,000
Startup Services (Controls)		$10,000
Tube Bending	$34,000	$34,000
Gas Piping	$11,800	$8,700
HTHW Flow Switches	$3,000	$2,500
Additional Safety Valve	$20,000	$10,000
Combustion Controls	$25,000	$20,000
Burner Cooling Ductwork & Fan	$32,000	$37,200
Power and Control Wiring	$6,700	$14,800
Subtotals	$252,500	$167,200
Total Material and Labor (1 Boiler)	$419,700	
Total Material and Labor (2 Boilers)	$839,400	
Mobilization	$42,000	
SubTotal	$881,400	
Overhead Supervision (15%)	$132,200	
Sub-Total	$1,013,600	
Profit (5%)	$50,700	
Contingency (10%)	$101,400	
Total for Burners	**$1,165,700**	

Appendix H: Example Life-Cycle Cost Analysis for the Revised Operation

Life Cycle Cost Analysis Study: MAFBREV.LC

WinLCCID FY99 12/14/01 16:29:15

Project no. FY & Title: Revised Operation

Installation & Location: Malmstrom AFB MONTANA

Design Feature:

Alternative:

Name of Designer:

Basic Input Data Summary

Criteria Reference: OMB Circular A-94

Discount Rate: 2.85 %

Key Project-Calendar Information

Date of Study (DOS) Dec-01

Midpoint of Construction (MPC) Dec-01

Beneficial Occupancy (BOD) Dec-01

Analysis End Date (AED) Dec-26

Cost/Benefit Description	Cost in DOS $	Equivalent Uniform Differential Escalation Rate	Time(s) Cost Incurred
Investment Costs	$650,100	0.00%	Dec01
Electricity	$30,030	-0.66%	Jun02-Jun26
Electric Demand	$0	-0.66%	Jun02-Jun26

```
|Natural Gas              |   $248,880|       0.77%| Jun02-Jun26 |

|Coal                     |   $717,561|      -0.85%| Jun02-Jun26 |

|         O&M Labor       |   $845,000|       2.20%| Jun02-Jun26 |

|         Ash Disposal    |    $97,952|       2.20%| Jun02-Jun26 |

|         Lime            |     $9,316|       2.20%| Jun02-Jun26 |

|     Maintenance Material  |    $90,000|       2.20%| Jun02-Jun26 |

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        Other Key Input Data


    Location - MONTANA                    Census Region: 4

    Rates for INDUSTRIAL Sector           Tables From:  Apr-99

================================================================

|   Energy Type    |    Unit Cost     |       Consumption       |  Projected
|

|===============|===============|================|=============|

|Electricity        |      $11.92 /MBtus|       2519.27001953 MBtus|  Jun02-
Jun26 |

|Electric Demand   |N/A                |                $0.00E+00K|  Jun02-
Jun26 |

|Natural Gas        |       $8.90 /MBtus|               27964 MBtus|  Jun02-
Jun26 |

|Coal               |       $2.88 /MBtus|              249153 MBtus|  Jun02-
Jun26 |

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Life Cycle Cost Analysis      Study: MAFBREV.LC

WinLCCID  FY99                          12/14/01 16:29:15

Project no. FY & Title:   Revised Operation

Installation & Location: Malmstrom AFB MONTANA

Design Feature:

Alternative:

Name of Designer:

                            Life Cycle Cost Totals

     Construction/Acquisition                                       Costs
   $650,100
```

Energy Costs
$17,079,092

Electricity
$493,284

Natural Gas
$5,000,817

Coal
$11,584,991

Water Costs
$0

Routine M&R/Custodial Costs
$2,156,794

Major Replacement/Replacement Costs
$0

Other Costs & Monetary Benefits
$22,820,491

Other Pre-occupancy Costs/Benefits $0

Net Disposal Costs or Retention Value $0

Other Capital Costs/Benefits $0

Other Operational Costs/Benefits $22,820,491

LCC of all Costs/Benefits (Net PW) $42,706,477

*Net PW Equivalents on Dec 01; in Single Dollars; in Constant Dec 01 Dollars

*Energy Escalation Rates from NIST Handbook 135 Supplement dated Apr 99

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Life Cycle Cost Analysis Study: MAFBREV.LC

WinLCCID FY99 12/14/01 16:29:15

Project no. FY & Title: Revised Operation

Installation & Location: Malmstrom AFB MONTANA

Design Feature:

Alternative:

Name of Designer:

Fuel and NonFuel Escalation Values

Location - MONTANA Census Region: 4

Rates for INDUSTRIAL Sector

==

FY	Electrici	Natural G	Coal	O&M Labor	Ash Dispo	Lime	Maintenan
1999	-1.03%	3.79%	-0.72%	2.50%	2.50%	2.50%	2.50%
2000	-1.19%	3.28%	-0.72%	2.50%	2.50%	2.50%	2.50%
2001	1.80%	3.18%	-0.73%	2.50%	2.50%	2.50%	2.50%
2002	1.40%	3.42%	-1.47%	2.50%	2.50%	2.50%	2.50%
2003	-1.02%	2.32%	-0.75%	2.50%	2.50%	2.50%	2.50%
2004	-2.93%	2.27%	0.00%	2.50%	2.50%	2.50%	2.50%
2005	-2.42%	2.53%	-1.50%	2.50%	2.50%	2.50%	2.50%
2006	-2.56%	0.93%	-0.76%	2.50%	2.50%	2.50%	2.50%
2007	-1.35%	0.31%	-0.77%	2.50%	2.50%	2.50%	2.50%
2008	-0.08%	0.00%	-1.55%	2.50%	2.50%	2.50%	2.50%
2009	-0.40%	-0.30%	-0.79%	2.50%	2.50%	2.50%	2.50%
2010	-1.30%	-0.61%	-0.79%	2.50%	2.50%	2.50%	2.50%
2011	-0.98%	-0.92%	-1.60%	2.50%	2.50%	2.50%	2.50%
2012	-0.83%	-0.62%	-0.81%	2.50%	2.50%	2.50%	2.50%
2013	-0.17%	0.00%	-1.64%	2.50%	2.50%	2.50%	2.50%
2014	-0.25%	0.31%	-0.83%	2.50%	2.50%	2.50%	2.50%
2015	-0.25%	0.31%	-0.84%	2.50%	2.50%	2.50%	2.50%
2016	-0.50%	0.31%	-0.85%	2.50%	2.50%	2.50%	2.50%
2017	0.34%	0.62%	-1.71%	2.50%	2.50%	2.50%	2.50%
2018	-0.84%	0.92%	-0.87%	2.50%	2.50%	2.50%	2.50%

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| 2019 |  -0.76% |   0.91% |  -0.88% |   2.50% |   2.50% |   2.50% |   2.50%
|

| 2020 |  -0.17% |   0.60% |  -0.89% |   2.50% |   2.50% |   2.50% |   2.50%
|

| 2021 |   0.00% |   0.60% |  -0.89% |   2.50% |   2.50% |   2.50% |   2.50%
|

| 2022 |   0.00% |   0.60% |  -0.90% |   2.50% |   2.50% |   2.50% |   2.50%
|

| 2023 |   0.00% |   0.89% |   0.00% |   2.50% |   2.50% |   2.50% |   2.50%
|

| 2024 |   0.00% |   0.59% |  -0.91% |   2.50% |   2.50% |   2.50% |   2.50%
|

| 2025 |   0.00% |   0.58% |  -0.92% |   2.50% |   2.50% |   2.50% |   2.50%
|

| 2026 |   0.00% |   0.58% |  -0.93% |   2.50% |   2.50% |   2.50% |   2.50%
|

================================================================

Routine M&R/Custodial Costs

Annual Value: Maintenance Material

Escalation Value: Maintenance Material

          Major Repair and Replacement Costs

          Other Operational Costs and Benefits

Annual Value: O&M Labor

Escalation Value: O&M Labor

Annual Value:          Ash Disposal

Escalation Value: Ash Disposal

Annual Value:          Lime

Escalation Value: Lime

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Life Cycle Cost Analysis      Study: MAFBREV.LC

WinLCCID  FY99                            12/14/01 16:29:15

Project no. FY & Title: Revised Operation

Installation & Location: Malmstrom AFB MONTANA

Design Feature:

Alternative:

Name of Designer:
```

Year-By-Year Breakdown of Life Cycle Costs

Costs Shown in Dollars

Pre-Occupancy Costs:

Construction/Acquisition $650,100

Other Pre-Occupancy $0

Beneficial Occupancy Date: Dec-01

Annual Payments occur: Jun-02 through Jun-26

Pay	Electricity	Natural Gas	Coal	Operational	Capital
1	$29,856	$249,377	$704,083	$1,040,493	$0
2	$29,317	$250,321	$675,329	$1,036,952	$0
3	$28,123	$249,005	$652,529	$1,033,423	$0
4	$26,565	$247,697	$632,847	$1,029,907	$0
5	$25,198	$246,281	$606,815	$1,026,402	$0
6	$23,922	$241,426	$585,490	$1,022,909	$0
7	$22,994	$235,334	$564,143	$1,019,428	$0
8	$22,327	$228,696	$540,702	$1,015,959	$0
9	$21,588	$221,567	$521,574	$1,012,502	$0
10	$20,729	$213,998	$502,412	$1,009,056	$0
11	$19,961	$206,252	$481,313	$1,005,622	$0
12	$19,269	$199,498	$463,524	$1,002,200	$0
13	$18,701	$194,071	$443,895	$998,789	$0
14	$18,137	$189,283	$427,993	$995,391	$0
15	$17,583	$184,611	$412,632	$992,003	$0
16	$17,033	$180,145	$397,219	$988,628	$0
17	$16,584	$176,326	$380,149	$985,263	$0
18	$15,991	$173,020	$366,396	$981,910	$0
19	$15,444	$169,677	$353,113	$978,569	$0
20	$14,995	$165,971	$340,286	$975,239	$0
21	$14,580	$162,340	$327,898	$971,920	$0
22	$14,175	$158,861	$316,416	$968,612	$0

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|  23|    $13,783|   $155,756|   $307,180|   $965,316|         $0|
|  24|    $13,401|   $152,330|   $295,949|   $962,031|         $0|
|  25|    $13,029|   $148,974|   $285,104|   $958,758|         $0|
|====|===========|===========|===========|===========|=========|
|Sum |   $493,284| $5,000,817|$11,584,991|$24,977,285|$0|
=================================================================
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Appendix I: Summary of Air Pollution Control Methods Used by Other DOD/Government Facilities That Burn Coal

Illinois (Rock Island Arsenal)

Description of Heat Plant: The central heat plant is located in Building 227 and is centrally located in the main manufacturing and administrative complex and operates year round to provide steam for heating, cooling, and process needs. Total steam capacity is about 400,000 lb/hr at 135 psig saturated steam. The plant has four (4) coal-fired boilers; each boiler has a maximum firing rate of 100, 100, 125, and 75 MMBtu/hr respectively. Particulate emissions from each boiler are initially ducted to a multicyclone that reduces particulates prior to entering the baghouse. Emissions are then ducted to one of two baghouses. The bags in the baghouses are the standard woven glass with 10 percent by weight Teflon B finish and replaced every five (5) years.

State EPA/Permit Requirements for Startup and Shutdown: Title 35 of the Illinois Administrative Code (IAC) 201.149 requires that a current operating permit allow for operations during startup. The facility currently operates under an operating permit that states the operation of the boilers in excess of the applicable emissions standards during startup is allowed. Also, IAC 201.261 provides the content requirements for a request to operate during startup. These requirements are met by the information provided in Form 203-CAAP, "Request To Operate During Startup of Equipment."

Rules and Requirements That May Be Violated During Continued Operation During Startup and Shutdown, and the Associated Regulated Air Pollutants: IAC 216.121, which limits CO emissions, maybe violated during startup. CO emissions are expected to increase because combustion is not complete during this time. All other emissions (SOx, NOx, opacity, and particulates) are not expected to exceed any limits. It is estimated that emissions through the startup period are approximately the same as those experienced during operations of the boiler in the baghouse bypass mode. IAC 212.202, which limits particulate emissions, may be violated during malfunction, if the baghouses are not operating properly. However, some malfunctions may not result in excess emissions.

Facility Measures Taken To Minimize Startup Emissions: The baghouse, that controls particulate emissions, is engaged during startup. In addition, emissions from each boiler are first ducted to a multicyclone, which reduces particulate emissions ducted to the baghouses. The plant ensures the coal is spread over entire grate before lighting to reduce warm-up time to a minimum of 3 to 4 hours. Stack emissions are also observed and draft fans are adjusted to minimize opacity. The plant will adjust the boiler stoker throws and operate the coal feed latches intermittently by hand to keep the coal from piling on the grates. If clinkering or piling of coal occurs, the operators will break up the clinkers or piles with a slag bar. Operators will observe the fire and start the overfire fan as soon as possible to reduce the startup time to a minimum. Operators will let the ash build up on the grate to a 1.5-inch thickness to prevent improper ignition of coal. In addition, operators will add additional modules as soon as temperatures in compartments and the outlet duct will permit.

Measures Taken To Minimize the Frequency of Startups: The plant will operate the boilers to 80 percent of its design heating load before starting an additional boiler. Once a boiler is brought on-line, it is normally kept in operation throughout the heating season. Boiler and baghouse breakdowns are minimized through good preventative maintenance and annual inspections, and other periodic inspections.

North Carolina (Marine Corps Base, Camp Lejeune)

Description of Heat Plant: The coal-fired heat plant on Camp Lejeune coal consists of five (5) separate boilers. Four of the boilers (ID Nos. 01, 02, 03, 04) burn coal or No.2 fuel oil; each boiler has a maximum heat input of 114.5 MMBtu/hr. One boiler (ID No. 05) burns No. 2 fuel oil and natural gas and has a maximum heat input of 95 MMBtu/hr. The plant's air pollution control device for boiler No. 5 is a flue gas recirculation system. For boilers No. 01, 02, 03, and 04, the plant uses two single-stage (three-cell), dry type electrostatic precipitators in series with four multicyclones and two ash collection systems. Each ash system consists of one wet scrubber installed in series with two cyclones installed in series with one ash collection silo. The plant also operates one No. 2 oil-fired emergency generator.

State EPA/Permit Requirements for Startup and Shutdown: Title 15A North Carolina Administrative Code (NCAC), Subchapter 2D was recently amended by declaring that the excess emissions during startup and shutdown are in violation unless the owner or operator can demonstrate that excess emissions are unavoidable. … The owner or operator shall, to the extent practicable, operate the source and any associated air pollution control equipment or monitoring equipment in a manner consistent with best practicable air pollution control practices to minimize emissions during startup and shutdown.

Rules and Requirements That May Be Violated During Continued Operation During Startup and Shutdown, and the Associated Regulated Air Pollutants: None

Facility Measures Taken To Minimize Startup Emissions: The plant limits startups on their coal-fired boilers. When the plant is warming up the ESP's, opacity is kept below 20 percent with air and fuel monitoring until the unit has fully warmed up. When the ESP's reach the minimum temperature, the cells are engaged to remove as much particulate matter as possible until the units are fully operational. If a boiler is needed for an emergency situation, the facility will engage the No. 5 unit on No. 2 fuel oil or natural gas. These emergency steps will reduce emissions until the coal-fired boiler can be restarted.

Measures Taken To Minimize the Frequency of Startups: Boilers are put on-line only when needed. They are in continuous operation until it is necessary for them to be shutdown due to repairs, maintenance, or when the heating load is reduced to justify a shutdown.

Ohio (Wright-Patterson Air Force Base)

Description of Heat Plant (Building 20770): The heat plant has three (3) 183 MMBtu/hr coal-fired steam boilers and two (2) 96 MMBtu/hr natural gas-fired steam boilers. The coal-fired boilers are operated at 400 PSIG that feed two 400 to 125 pressure-reducing stations that feed area "B" of the base. The heat plant is not allowed to burn coal during the months of June, July, and August, only gas. The plant uses pulse jet filter bag houses for the coal-fired boilers to control particulates. Make up water is supplied by a reverse osmosis system.

State EPA/Permit Requirements for Startup and Shutdown: Ohio Administrative Code, (OAC), Chapter 3745-31, governs the terms and conditions of plant operation. "To obtain an exemption from the visible emissions limitations specified in OAC rule 3745-17-07(A), the permittee shall operate and maintain a temperature monitor that measures the temperature of the boiler exhaust gases entering the baghouse (a) during all periods of startup … until the inlet temperature of the baghouse achieves a temperature of 350 degrees Fahrenheit (b) during all periods until the baghouse temperature drops below 350 degrees Fahrenheit. The permit states that all three (3) boilers must meet the following emissions limitations:

Particulate emissions will not exceed 0.10 lb/MMBtu actual heat input

Sulfur dioxide (SO_2) emissions will not exceed 2.00 lb/MMBtu actual heat input

Nitrogen oxide (NOx) emissions will not exceed 0.60 lb/MMBtu actual heat input

Testing to demonstrate compliance with allowable emission rates is done every three years, and is completed while the emissions unit is operating at the maximum allowable capacity. The facility is also required to provide, to the Ohio EPA District Office, a written quality assurance/quality control plan for their continuous monitoring equipment.

<u>Rules and Requirements That May Be Violated During Continued Operation During Startup and Shutdown, and the Associated Regulated Air Pollutants:</u> None

<u>Facility Measures Taken To Minimize Startup Emissions:</u> The facility cannot engage the baghouse when the inlet temperature is below 350 degrees Fahrenheit; therefore the facility achieves that temperature as quickly as possible. According to operational procedures, the facility achieves an inlet temperature of 250 degrees Fahrenheit as quickly as possible and then increases boiler outlet temperature no quicker than 75 degrees Fahrenheit per hour after that. With the flue gas oxygen content held under 10 percent, the facility can engage the baghouse as soon as they obtain 350 degrees Fahrenheit on the baghouse inlet.

<u>Measures Taken To Minimize the Frequency of Startups:</u> Emergency startups due to mechanical failure are lowered by a good preventative maintenance program that is constantly updated as experience shows them what should be accomplished and how often. They start with manufacture's recommendations and then modify the tasks according to the machinery's characteristics. They also had a stack plume air flow outlet study performed to get their maximum output raised from 150 MMBtu/hr to 169 MMBtu/hr. This increase in heat output allowed the base to provide more steam without having to put another boiler on line, thus potentially saving another startup.

Texas (Red River Army Depot)

Description of Heat Plant: The central heating plant has three (3) Voigt coal/wood-fired steam boilers each rated at 50,000 lb/hr. The steam is used for process operations and comfort heating requirements.

State EPA/Permit Requirements for Normal Operation, and Startup and Shutdown: Section 382.0518 of the Texas Clean Air Act, Texas Health, and Safety Code, Chapter 382, and 30 Texas Administrative Code Section 116.116(c), imposes the following emissions limitations:

Particulate emissions will not exceed 0.10 lb/MMBtu actual heat input

Sulfur dioxide (SO_2) emissions will not exceed 1.20 lb/MMBtu actual heat input

Nitrogen oxide (NOx) emissions will not exceed 0.70 lb/MMBtu actual heat input

Testing to demonstrate compliance with allowable emission rates is completed while the emissions units are operating at the maximum firing rates. The Texas Natural Resource Conservation Commission (TNRCC) can request a test at any time. The facility is also required to demonstrate, through calculations, SO_2 emissions based on: percent sulfur in coal, feed rates, AP42 emission factors, and MMBtu/hr.

In addition, the following table lists the maximum allowable emission rates, by source of contaminants, for each boiler: (Emission rates extracted from permit)

Contaminant	Emission Rate (lb/hr)
Particulates	6.0
Nox	42.0
SO_2	72.0

Demonstration of compliance with emission standards in special Condition No. 2 (SO_2 emissions) and the maximum emission allowable rates (as stated above) shall be performed in accordance with calculation methodology (% sulfur content of coal, lb/hr feed rate, MMBtu/hr) represented in permit alteration correspondence dated 28 November 2000. This correspondence has no reference to these calculations during boiler startup or shutdown. The plant is, however, required to report any upset conditions to the TNRCC.

Rules and Requirements That May Be Violated During Continued Operation During Startup and Shutdown, and the Associated Regulated Air Pollutants: None

Facility Measures Taken To Minimize Startup Emissions: The plant ensures a proper feed rate and controlled air settings. Wood is burned during startup to lower SO_2 emissions.

Measures Taken to Minimize the Frequency of Startups: The plant ensures proper operations of all equipment. The plant also implements an effective preventive maintenance schedule.

U.S. Capital (Washington, DC)

Description of Heat Plant: The U.S. Capital Heat Plant has seven (7) boilers. Boilers 1, 2, and 3 each have a capacity of 160K lb/hr @ 200 psig saturated steam. Boilers 1 and 2 burn coal (spreader stoker with traveling grate), and are co-fired with natural gas. They use a cyclone mechanical dust collector and baghouse is used for pollution control. Boiler 3 is fueled by natural gas and No. 2 fuel oil; it uses a cyclone mechanical dust collector for pollution control. Boilers 4 – 7 each have a capacity of 50K lb/hr @ 200 psig saturated steam and burn No. 2 fuel oil.

District EPA/Permit Requirements for Startup and Shutdown: Chapter 3, Operating Permits, of Title 20 of the District of Columbia Municipal Regulations (20 DCMR) describes the requirements and limitations for operation. The permit states that all seven (7) boilers must meet the following emissions limitations:

Boiler	Particulates (lb per MMBtu)	Opacity	NOx (lb per MMBtu)
Nos. 1 & 2	0.05 (a)	10%/40%/15%/30% (b)	0.43/0.7/0.4/0.35 (c)
No. 3	N/A	10%/40%/15%/30% (b)	0.2
Nos. 4 - 7	N/A	10%/40%/15%/30% (b)	0.25/0.30 (d)

Compliance is measured when the flue gas from the two boilers is exhausted through the baghouse.

The opacity limit of 10 percent (unaveraged) can be exceeded under the following conditions: 40 percent (unaveraged) for two minutes per hour and for an aggregate of twelve minutes per 24-hour period other than during startup. During startup, 40 percent (averaged over six minutes) up to five times per startup.

During shutdown, 15 percent (unaveraged) with 30 percent (averaged over three minutes) up to three times per shutdown.

The NOx emission limit of 0.43 lb per MMBtu based on a calendar day average; 0.70 lb per MMBtu is based on a two-hour average, and 0.40 lb per MMBtu from May to Oct. The plant should use its best efforts to meet 0.35 lb/MMBtu.

The NOx emission limit of 0.25 lb per MMBtu based on a calendar day average; 0.30 lb per MMBtu is based on a two-hour average.

Rules and Requirements That May Be Violated During Continued Operation During Startup and Shutdown, and the Associated Regulated Air Pollutants: None

Facility Measures Taken To Minimize Startup Emissions: For boilers 1 and 2, the plant only uses natural gas for startup. For boilers 3 – 7, the plant does not take any added measures to minimize emissions. The baghouses are also engaged at the beginning of each startup to minimize opacity and particulate emissions.

Measures Taken To Minimize the Frequency of Startups: The plant, through the use of historical data, forecasts load fluctuations to minimize the need to startup new boilers. They also have an excellent maintenance program and strive to leave boilers on-line for extended periods of time.

Summary of Coal-Fired Boilers

Location	Type of Coal Feeder	Air Pollution Control Method During Steady State	Air Pollution Control Method During Startup	Average No. of Times Per Year Each Boiler Starts Up	Maximum Percent of Sulfur in Coal/Oil
Illinois (Rock Island Arsenal)	Spreader-stoker & traveling grate	Cyclone mechanical dust collector and baghouse	Cyclone mechanical dust collector and baghouse	1	Coal: 1.4%
Montana (Malmstrom Air Force Base)	Spreader-Stoker	Scrubber and baghouse once flue gas temp reach 350 °F	Engaging the baghouse as quickly as the manufacturer's limitations and permit rules allow	5-6	Coal: 1.0%
North Carolina (Marine Corps Base, Camp Lejeune)	Stock brand feeders with a variable drive belt system	Flue gas recirculation, electrostatic precipitator with a multicyclone, an ash collector with wet scrubber and cyclone, and ash collection silo.	Opacity is kept below 20% with air and fuel monitoring. When ESP's reach min. temp, cells are engaged until the units are fully operational.	6	Oil: < 0.5% Coal: < 1.3%
Ohio (Wright-Patterson Air Force Base)	Detroit Stoker: Overthrow spreader stokers	Pulse jet filter bag house once flue gas temp reach 350 °F	Engaging the baghouse as quickly as the manufacturer's limitations and permit rules allow	< 3	Coal: 0.85% to 1.3%
Texas (Red River Army Depot)	Detroit Spreader Stoker Reciprocatin g Feeder	Baghouse filters for each boiler	Proper feed rate and correct air settings	15 to 20	Coal: 0.69%
U.S. Capital (Washington, DC)	Spreader-Stoker	Cyclone mechanical dust collector and baghouse	Cyclone mechanical dust collector and baghouse	2	Coal: 1.0%

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14. ABSTRACT

The Coal-Fired Heat Plant (CFHP) at Malmstrom Air Force Base (MAFB), MT is designed to fire both natural gas and sub-bituminous coal. Under normal operating conditions, the coal-fired generators meet the Montana Department of Environmental Quality (MDEQ) emission standards. However, under certain nonstandard (i.e., startup, shutdown, and malfunction) conditions, the plant may exceed emission limits.

MAFB tasked the U.S. Army Engineer Research and Development Center, Construction Engineering Research Laboratory (ERDC/CERL) to conduct a study to determine emission limits during startup, shutdown, malfunction, and scrubber bypass, to make appropriate recommendations to help MAFB maintain the heat plant in compliance with permit requirements at all times when fired on coal, or to recommend alternative fuels and equipment to maintain compliance. The study concluded that the MAFB CFHP can able to meet its current permit limits through equipment modifications and operational changes. A possible alternative to the operational changes would be to pursue a change to the Montana System Implementation Plan (SIP) and/or their CFHP operating permit.

15. SUBJECT TERMS

coal fired heat plant (CFHP)	emissions	Malstrom AFB, MT
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